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Safety, Reliability, Profitability

– the main drivers of a good integrity management system

Heinz Watzka
EITEP Senior Advisor

Pipelines are the veins of a worldwide energy system, serving industry and clients with all kinds of liquids and hazardous fluids and gases. In the 1920s to 1950s they have been built with a commercial lifetime of 25 to 30 years, but today some of the systems are reaching their 100 years of operation anniversary. The main bulk of high pressure transmission lines in the oil and gas industry will have their 50 or 70 years anniversary. Aging infrastructure per se is no problem for safe operation as long as best maintenance procedures and methods are applied.

Today's successful operation within the oil and gas industry is based on the triangle "Safety - Reliability - Profitability (Efficiency)". It is of high importance to properly balance these different and sometimes opposite positions.

High technological and operational standards guarantee safety for human and environment. Innovative technologies ensure security of supply and grant reliability. Competitive service provides efficient transmission conditions for the client and stands for profitability.

Different company management systems support the a. m. triangle. A well-advanced Pipeline Integrity System (PIMS) is a major success factor for integrity within technics, organisation and information within the organisation of the transportation system operator (TSO). The relevant standards and codes in Europe (DIN EN 16348) establish the targets of a PIMS with PDCA (Plan-Do-Check-Act) methodologies, relevant documentation, well-defined organizational structures, safety aspect/targets/programs, communication and the development of clear and smart KPIs.

Despite its high population density, Germany reaches the highest safety figures (oil and gas transmission systems) compared to international records and publications. Key for this positive trend is the establishment of a well-advanced PIMS with regular third-party checks and experience exchange between the different operators and their associations (DGMK and DVGW).

A further increase of safety and therefore decrease of accidents and incidents may be reached with a strong exchange of experience between operators, service companies and manufacturers and furthermore the regulator as the external and responsible part of the a. m. triangle. Long-term commercial cooperation between operators and manufacturers are further possibilities to overcome lack of knowledge due to demographic challenges.

It must be a clear and communicated target for the responsible TSOs to establish international platforms for the proposed experience exchange and integration of relevant authorities and regulators. Based on well-advanced and creative communication, this challenge also may improve the missing acceptance of our society (public perception) in respect of pipeline projects and future energy demands. Some few events already take care of this idea but the international pipeline community still has plenty of room for further improvement.

This edition of ptj focuses on new developments in intelligent data management from ILI runs, advanced PIMS methods and new sensors and procedures for improving pipeline integrity. All these developments are part of a company's PIMS and the triangle mentioned above and will support TSOs in keeping their license to operate.

Yours,

H. Watzka

Heinz Watzka, EITEP Senior Advisor,
former Technical Director of Open Grid Europe

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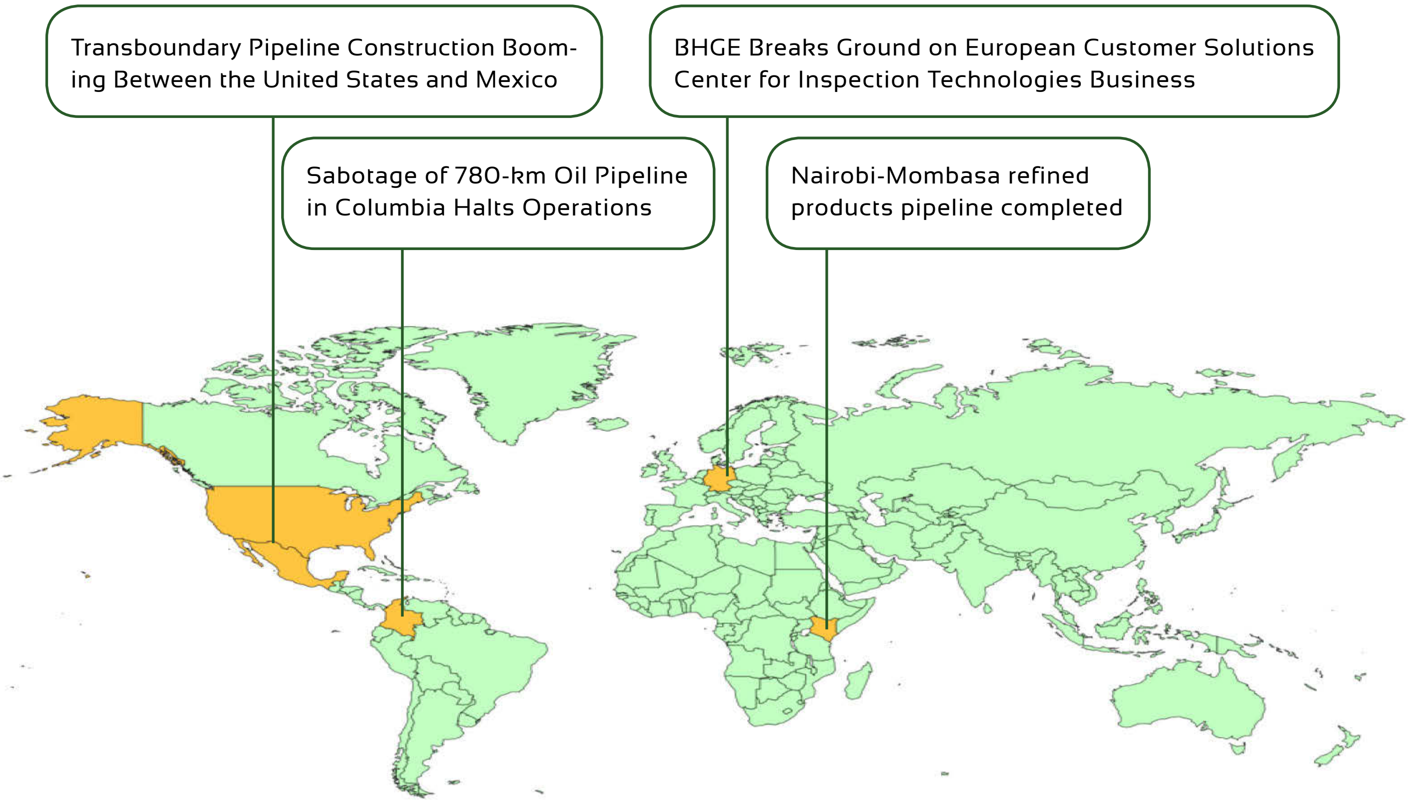
WORLD NEWS



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INDUSTRY NEWS

Creaform and Olympus Announce Worldwide Distribution Agreement for Pipeline Integrity Assessment Solution

Olympus now distributes Creaform's Pipecheck Analyze software

Creaform, a well known company in the business with portable 3D measurement solutions and engineering services, announced has announced that Olympus® Scientific Solutions Americas, a manufacturer of phased array flaw detectors for corrosion inspection, will now distribute Pipecheck™ Analyze, a ophisticated NDT software for pipeline integrity assessment. Pipecheck™ Analyze software solution supports phased array (PA) and conventional ultrasonic testing (UT) data files for corrosion analysis and allows users to gain important information about the status of their components.

"We are very proud to partner with Olympus and to integrate OmniScan® data with our code compliant corrosion software analysis. The capability of analyzing internal and external corrosion separately or together pushes pipeline assessment to another level," says Steeves Roy, NDT Product Manager at Creaform.

With Pipecheck, NDT service companies and pipeline engineers can get more reliable and traceable analyses to ensure a safe assessment. Pipecheck to this day is the only trusted solution available that enables the identification of potential issues on both the inner and outer linings of pipes using both ultrasonic testing and 3D scanning, whether they be corrosion, dents or gouges in the metal.

Pipecheck can now process data from 3D scanners as well as data from ultrasonic testing devices, such as the Olympus' OmniScan. Pipecheck provides true wall thickness assessment analysis based on the combination of various integrity assessment calculations. Adding Pipecheck to Olympus' product offering will enable users to use phased array ultrasonic testing (PAUT) data, and combine that data with the advanced algorithms and strength calculations offered within Pipecheck, to create a very accurate and realistic damage evaluation of pipeline integrity.

GE plans to split from Baker Hughes

Despite the fact that Baker Hughes just recently joined the General Electric group, the financially struggling American company publicly announced its intention to separate from Baker Hughes in the next two or three years.

The reason for this move lies in the intention of GE to focus on its more profitable branches aviation, power and renewable energy. GE will therefore separate from its branches health care and transportation. The decision came after the company has undergone an internal strategic review. Because Baker Hughes has got a two-year-lockup-agreement with General Electric, the split is not likely to be finalized until 2020.

The announcement is only partially a surprise, since GE's CEO John Flannery said in the past, shortly after the merger, that he will seek ways out of the deal. Flannery was appointed CEO in August 2017, long after the merger was a done deal.

Baker Hughes remains optimistic about the split. The company has benefits regarding the access to GE's technologies and a favorable market position, as a company spokesperson stated.

Pipeline Transport Institute completes test runs of pipeline transportation hydrodynamic processes test bench

The Pipeline Transport Institute has successfully completed factory testing of a self-developed test bench for studying hydrodynamic processes related to pipeline transportation of oil and petroleum products.

This test bench, which has a variable profile, will allow experts to study transient processes in multiphase hydrocarbon flows, including simulating and studying flow of liquid via a gravity flow pipeline (with the possibility of changing the profile of the pipeline) and modelling batching of various hydrocarbon fluids as well as hydraulic shock, gas removal from the pipeline, accumulation of water at low points and water removal at different angles of inclination of pipelines. In addition, it will be possible to simulate oil and petroleum products leakage as well as to test methods of detection thereof.

The newly developed test bench will provide the necessary conditions for analysing the effectiveness of technological solutions before their actual implementation at entities of the Transneft system. Transneft and entities of the Transneft system have obtained patents for the technical solutions underlying the test bench.

The test bench will be installed at the premises of the Pipeline Transport Institute's Research and Development Centre in Ufa. Installation will be complete and the bench will be commissioned in Q4 2018.

TransCanada has awarded Spiecapag and Macro Pipelines to build two sections for the Coastal GasLink gas pipeline project in Canada

A pipeline welder works on an extension of the NGTL System, in Northern Alberta, Canada (Copyright: TransCanada)

Canadian energy infrastructure operator TransCanada Corporation has awarded a contract to a joint venture made up of Spiecapag Canada Corp, a VINCI subsidiary and operational leader, and Macro Pipelines Inc. to build two sections of gas pipeline in the province of Vancouver, British Columbia.

The C$900 million (about €585 million) contract includes the construction of more than 166 kilometres of gas pipeline as part of the 670 km Coastal GasLink Pipeline. The contract amount is split, with 60% going to Spiecapag and 40% to Macro Pipelines Inc.

The joint venture will carry out a pre-construction planning phase pending a positive final investment decision by LNG Canada* for a proposed natural gas liquefaction facility in Kitimat, British Columbia. The decision is expected in the fourth quarter of 2018, with construction set to get under way in early 2019.

"Alongside our joint venture partner Macro Pipelines Inc., we are proud to be part of the Coastal GasLink Pipeline Project and to furnish our expertise in gas pipeline construction. Our ability to perform works in mountainous environments with steep slopes enabled us to win this large contract. Additionally, the project will provide opportunities to qualified local businesses and suppliers along the pipeline route and employment for roughly 900 people hired directly," said Bruno Guy de Chamisso, Chief Executive Officer of Spiecapag.

In October 2017, Spiecapag and its partner Macro Pipelines Inc. also won the contract in British Columbia to build a 36-inch oil pipeline as part of the Trans Mountain Expansion Project.

Pipeline Transport Institute presents energy efficiency benchmarking results to International Association of Oil Transporters

A meeting of the Permanent Expert Group for Energy Efficiency of the International Association of Oil Transporters (IAOT) has been held in Prague (the Czech Republic).

The meeting brought together representatives of Transneft, The Pipeline Transport Institute (PTI), MERO ChR (the Czech Republic), Transpetrol (Slovakia), Gomeltransneft Druzhba (Belarus), MOL (Hungary) , KazTransOil (Kazakhstan), CPC-R, the China National Petroleum Corporation (CNPC) and Ukrtransnafta, that has recently joined the association.

Yakov Fridlyand, Director General and Chairman of the expert group for energy efficiency, and Bronislav Grisha, Head of the Energy Efficient Technologies of Oil and Petroleum Products Transportation Laboratory, represented PTI at the event.

Results of the pipeline transport energy efficiency benchmarking assessment held by PTI in 2017 at 20 process sections of pipelines belonging to the association's member states were presented at the meeting. The calculations took various technical parameters and properties of the crude oil transported via all the pipelines covered by the study into account.

The study results indicated that accomplishment of measures to enhance energy efficiency of crude oil transportation via pipelines of the IAOT member states enabled a 3.5% drop in average specific energy consumption in 2017 versus 2016. The studies also contained recommendations on how to curtail energy consumption further. PTI offered the participants to share the best practices of energy efficiency benchmarking among companies of the oil and gas sector.

NDT Global Appoints President

NDT Global, supplier of ultrasonic pipeline inspection robotics and integrity services solutions, today announced the appointment of Mr. Richard Matthews as the President of NDT Global.

With more than 30 years of experience in the oil and gas industry and most recently held the position of Operations Director for PIMS of London, Mr. Matthews' appointment supports NDT Global's product strategy and continued growth in developing service solutions to meet the future needs of the industry.

"I am both honored and delighted to be the President of NDT Global. I believe our customer-driven research and development focus, along with a commitment to operational rigor and discipline, ensures that we continue to offer the best value pipeline assurance solutions in the industry." Mr. Matthews commented.

Based at NDT Global headquarters, he will be responsible for implementing the organization's strategy and driving the day-to-day business of the company, including the delivery of high-accuracy pipeline robotic solutions for the inspection of cracks, metal loss and mechanical damage to the oil, gas and petrochemical industries worldwide.

BHGE Breaks Ground on European Customer Solutions Center for Inspection Technologies Business

Baker Hughes, a GE company, has broken ground on a new European Customer Solutions Center (CSC) for its Inspection Technologies (IT) business, one of the world's leading providers of non-destructive testing (NDT). The CSC will be housed on IT's existing Wunstorf, Germany site and will be the flagship CSC for European customers and partners. BHGE will invest a significant amount in the millions of dollars in the new 9.250 sqm CSC and plans to add up to 100 jobs to the Wunstorf site as part of the project.

The announcement follows the grand opening of IT's largest CSC globally in Cincinnati, USA, earlier this year. Like Cincinnati, the Wunstorf CSC will also bring the most advanced NDT technologies under one roof, including x-ray, CT, ultrasonic, remote visual inspection and sensor solutions. Given the Wunstorf site's heritage as BHGE's radiography centre of excellence, the CSC will have a specific focus on 2D X-ray systems and 3D computed tomography (CT), supplemented by high-tech applications for ultrasonic and electromagnetic inspection. In addition, the facility will also house managed services for parts inspection and allow for personalized setups for training and collaboration.

"The manufacturing industry is changing, and Industrial Internet of Things coupled with our innovation in X-ray, CT, and other inspection technologies enables us to set new standards in industrial quality and product reliability assurance," said Holger Laubenthal, CEO of Inspection Technologies for BHGE. "We will support our customers through this change and that's where a place like this Customer Solutions Center will be a huge asset. Here in Wunstorf, our experts will work together with our customers to develop technologies to solve individual challenges. We like to see ourselves as problem solvers, and I believe no one else in the industry can offer this level of high-quality service for non-destructive testing. "

Russian Edition of ptj Pipeline Technology Journal agreed

The international publishers EITEP and Radiofront have agreed to implement a Russian-speaking edition of the Pipeline Technology Journal (ptj). Both companies are committed to meet the high demand for top-class pipeline technology case-studies, technical articles and current industry news. The new Russian edition ("ptj-Вестник трубопроводных технологий") will be available in Russia, Belarus, Ukraine and Uzbekistan. Its content will be similar to the original ptj but enriched with additional content related to the Eastern European pipeline industry.

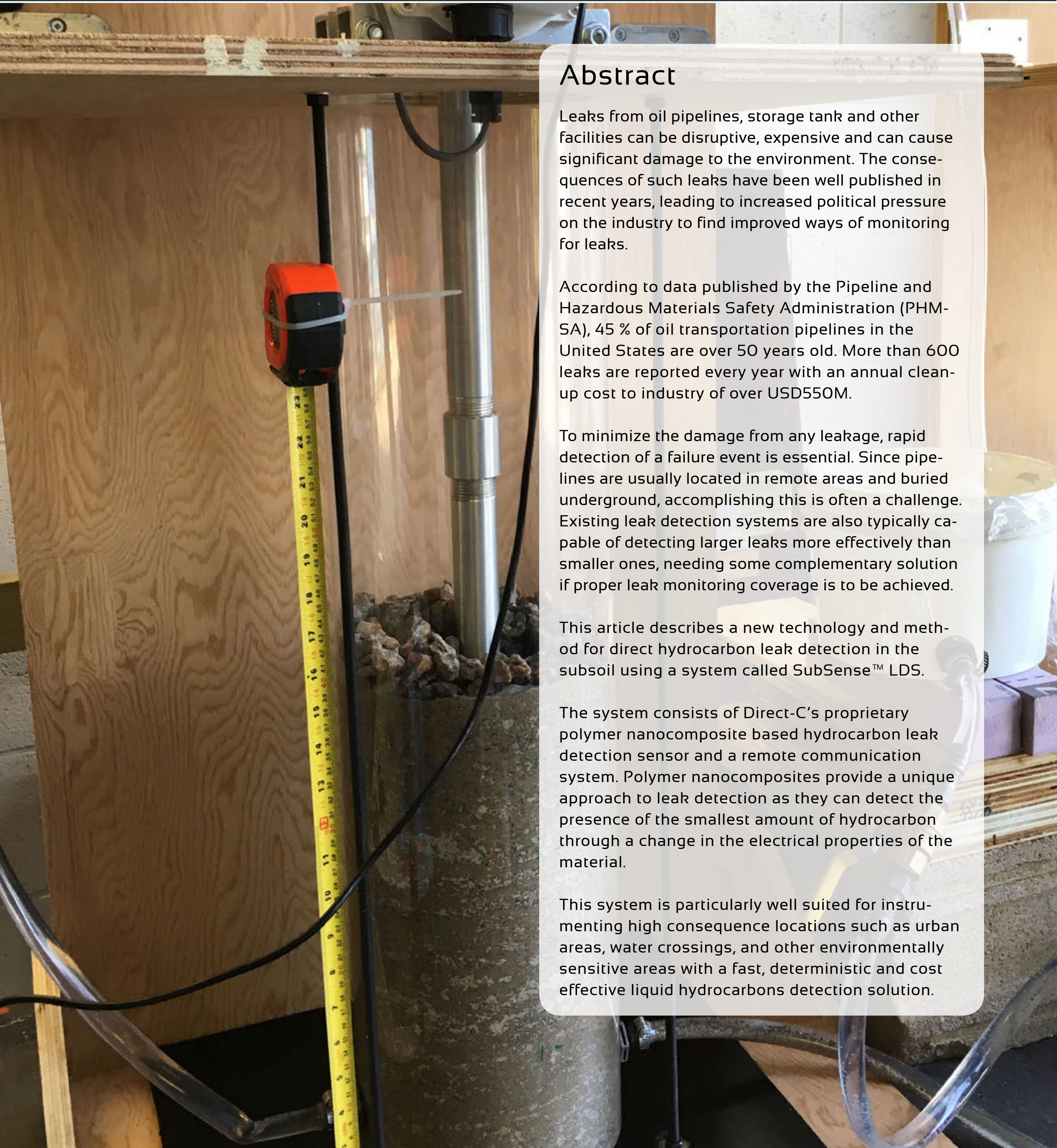
This cooperation enables international pipeline technology and service providers interested in the Russian market to show their know-how and to advertise specifically in an edition distributed in Russia and its neighboring countries. Vice versa, Russian pipeline companies can provide their content and advertisements for publication within the original ptj. For all readers, this cooperation means a better access to insightful technical articles from oil & gas operators and technology & service providers.

"The appearance of the Russian version of the ptj is a logical continuation of the EITEP strategy aimed at the creation of a common platform for intense technology exchange between international pipeline operators, service & technology providers.", said Dr. Klaus Ritter, President of EITEP, who is also well-known for the annual Pipeline Technology Conference (ptc). "Such an exchange will help the global pipeline industry to minimize incidents and to maximize pipeline safety, longevity and profitability", he added.

His counterpart, Aleksey Turbin, General Manager at Radiofront, stated: "Russian companies are keen to be involved in the impressive efforts of EITEP to foster the exchange of state-of-the-art-technologies and best-practices. The Russian edition of ptj ist going to be of great use for achieving this worthwhile goal which is in correspondence with the trend of technology globalization".

Development of a Novel Subsurface Monitoring and Oil Leak Detection System - SubSense LDS

Dr. Stephen Edmondson; Dr. Kaushik Parmar; Adrian Banica
> Direct-C



Abstract

Leaks from oil pipelines, storage tank and other facilities can be disruptive, expensive and can cause significant damage to the environment. The consequences of such leaks have been well published in recent years, leading to increased political pressure on the industry to find improved ways of monitoring for leaks.

According to data published by the Pipeline and Hazardous Materials Safety Administration (PHMSA), 45 % of oil transportation pipelines in the United States are over 50 years old. More than 600 leaks are reported every year with an annual clean-up cost to industry of over USD550M.

To minimize the damage from any leakage, rapid detection of a failure event is essential. Since pipelines are usually located in remote areas and buried underground, accomplishing this is often a challenge. Existing leak detection systems are also typically capable of detecting larger leaks more effectively than smaller ones, needing some complementary solution if proper leak monitoring coverage is to be achieved.

This article describes a new technology and method for direct hydrocarbon leak detection in the subsoil using a system called SubSense™ LDS.

The system consists of Direct-C's proprietary polymer nanocomposite based hydrocarbon leak detection sensor and a remote communication system. Polymer nanocomposites provide a unique approach to leak detection as they can detect the presence of the smallest amount of hydrocarbon through a change in the electrical properties of the material.

This system is particularly well suited for instrumenting high consequence locations such as urban areas, water crossings, and other environmentally sensitive areas with a fast, deterministic and cost effective liquid hydrocarbons detection solution.

POLYMER NANOCOMPOSITE (PNC) COATINGS FOR HYDROCARBON DETECTION

The sensor system is comprised of a sensing element consisting of a silicon-based polymer embedded with conductive nanoparticles. This system was developed at the University of Calgary by Dr. Park and Dr. Parmar.

The polymer's characteristic of swelling in the presence of hydrocarbon molecules is exploited. The polymer also provides the advantage of being hydrophobic and thus unaffected by water and ice.

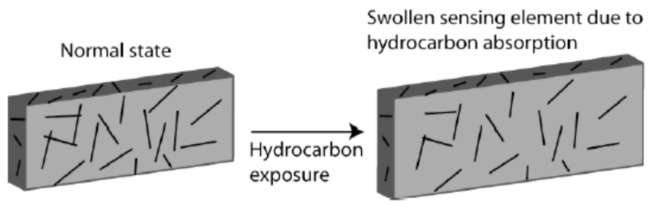


Figure 1: Effect of Hydrocarbon Exposure on Polymer Nanocomposite Coating

The silicone-based polymer swells upon absorption of hydrocarbon molecules, causing increases in the distances between nanoparticulates thereby increasing the resistance of the silicone-based nanocomposite polymer coating as shown above.

Hydrocarbon	Instantaneous Slope (degrees)	Type of Response
Pentane	89.3	High
Octane	88.8	High
Diesel	73	Medium
Crude Oil	9	Low
Motor Oil	6	Low

Table 1: Change in Resistance of the PNC Coating on Exposure to Liquid Hydrocarbons

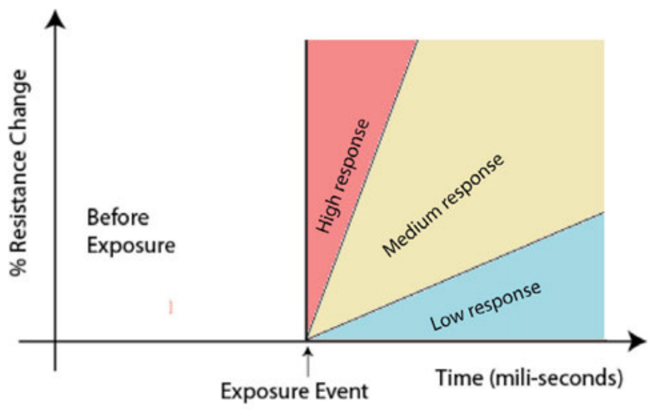


Figure 2: Response of the Polymer Nanocomposite Coating

> *24/7 monitoring, zero false positives*
> Dr. Stephen Edmondson

The polymer nanocomposite coating employed in the SubSense™ unit was formulated as to not be affected by methane thus eliminating any false positives caused by naturally occurring methane. Instead, it was tuned to detect C5 to C24 liquid hydrocarbons. The effect of the exposure of this coating to 5 ml of various liquid hydrocarbons is shown in the table and graph above.

Since the detection method is based on the rate of change in resistance of the sensor, the type of hydrocarbon can be determined. This enables the discrimination, in a situation where several different hydrocarbons are being stored or transported close to a given sensor, of which particular hydrocarbon has leaked.

This also eliminates the false positive caused by the "wrong" type of hydrocarbon coming into contact with the sensor, for example a spill of diesel fuel onto a sensor would trigger a different sensor response compared to a leak of crude oil from a pipeline onto the same sensor.

ADVANTAGES OF NANOCOMPOSITE BASED DETECTION - ELIMINATION OF FALSE POSITIVES

A common problem with leak detection systems that use a secondary measurement such as acoustic or flow to detect leaks and infer the presence of a hydrocarbon, are false positives. These false alarms are generated when the presence of a hydrocarbon is falsely inferred due to interferences by other disturbances. For SubSense™ we have analyzed the potential routes to a false positive detection and determined if our detection algorithm would generate a false alarm under those conditions.

Cause	PNC Sensor System	False Positive Possible
Oil Present	Resistance increases at 6° in 10 s. to over 100 %	-
Sensor Power Fails	Signal drops to 0	No
Sensor Circuit Breaks	Resistance goes to ∞	No
High Temperature	Change of < 20 % in Resistance	No
High Pressure	Resistance decreases	No
Water	No change	No
Other Chemicals	Resistance increases if polymer swells	Yes
Shear Force applied	Resistance goes to ∞	No

Table 2: Possible Routes to a False Positive

The algorithm used for detecting hydrocarbons is based on an increase in resistance of the coating with a minimum 6 degree initial slope and a change in resistance of over 100%.

The only identified route to a false positive is exposure to a chemical which would cause swelling at the same rate and magnitude as that given from an exposure of the sensor to hydrocarbons. There are no environmentally available chemicals that are known to cause such a response, therefore environmental exposure will not generate false alarms.

All other causes described above will give a very different change in the detected signal, which would be measured by the monitoring system and reported, but would not generate an alarm indicating the presence of hydrocarbon.

CONFIGURATION OF SUBSENSE™ UNITS

The SubSense™ Leak Detection sensor and communication system is primarily targeted at existing liquid hydrocarbon pipelines and storage facilities. The unit is installed in a hydrovac'ed hole next to the pipeline and located in the expected leak path of the hydrocarbons. It features the proprietary Surface Access Port (SAP) installation to allow the hydrocarbon to readily come into contact with the sensing elements.

The key performance criteria that are desired for any leak detection systems are listed below:

Performance Criteria	Optimal / Target	SubSense Capability
Reliability	> 2 years between servicing	High
Location Detection Accuracy	+ / - 10 meters	High
Sensitivity / Scale of Leak	< 5m3 / hour	Very High
Speed / Response Time	Within a few minutes	1 minute
Continuous Monitoring	Continuous monitoring 24/7	Yes
Direct Detection	Direct detection, no False Positives	Yes
Effective in Steady-state & transient conditions	Steady-state & transient	Yes

Table 3: Performance Criteria for Leak Detection Systems

The SubSense™ unit features four sensors located in a hollow tube at the base of the unit and a communication package at the top of the tube which contains a modem to send out data as shown here.

There are a number of communication options, in this instance a cellular modem was used to send a signal out when a hydrocarbon was detected.

A satellite modem or local radio system could also be employed.

TESTING OF SUBSENSE™ UNITS

The objective of the testing program was to demonstrate the operation of a SubSense LDS sensor in a laboratory environment using a setup representative of field conditions.

During this testing program, the prototype sensor was placed in a similar soil sample that it would see in the field.

The sensor within the test setup was surrounded by gravel inside a porous PVC pipe, similar to field installation methods. The porous PVC pipe was surrounded by sand contained in a clear acrylic tube or standpipe to visually observe the oil contamination level. The contaminants (gasoline, diesel fuel and crude oil) were

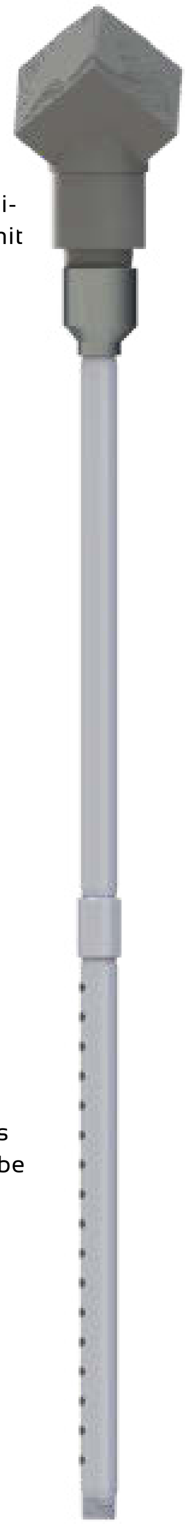


Figure 3: SubSense™ Unit Description

Figure 4: Test Set Up at C-Core

The algorithm employed to send the text message was the detection of a high initial gradient when the resistance changed on exposure of the sensor to a hydrocarbon, it was not based on the total change in resistance.

TEST RESULTS WITH HYDROCARBONS

Prior to Gasoline exposure testing, a sensor was held submerged overnight in well water (high mineral content) to simulate a flooded or submerged condition.

No change in voltage was observed.

On exposure to gasoline, all three sensors triggered. The response was very rapid due to the relatively short chain hydrocarbons present in the product.

All three sensors triggered a text message alert to a cell phone. The algorithm was set to alert for the smaller chain hydrocarbons, so this response was expected.

On exposure to Oil, all three sensors triggered as shown n Figure 5 and 6. The response was less rapid than for the other hydrocarbons, as expected, therefore no text message alarm was sent.

The algorithm was set to alarm for smaller chain hydrocarbons, this shows that SubSense has successfully alarmed for smaller chain length hydrocarbons exposure and has not alarmed due to crude oil exposure.

The alarming algorithm can be tailored to enable the alerting of particular types of hydrocarbons and to eliminate false positives due to other chemicals coming into contact with the sensor.

then introduced through a port in the side of the acrylic standpipe. The contaminants flow through the sand and into the sensor tube.

The sensor readings were monitored to determine when they changed indicating the presence of a hydrocarbon.

The sensor was exposed to three types of hydrocarbon:

1. Gasoline- 87 octane from local gas station
2. Diesel- from local gas station
3. Crude Oil- 857 density

The reservoir bucket was filled with the contaminant hydrocarbon fluid. As the fluid level increased, the sensor was monitored to determine if the voltage changed upon contact with the hydrocarbon.

A positive response, or trigger, could be indicated either by the sending of a text message from the unit to the operator or by the observation of a rise in voltage from the laptop data acquisition system showing the sensor input rise from approximately 1 volt to 2.9 volts.

The test was complete when either all sensors triggered along the test strip or when the fluid level had passed all of the sensors.

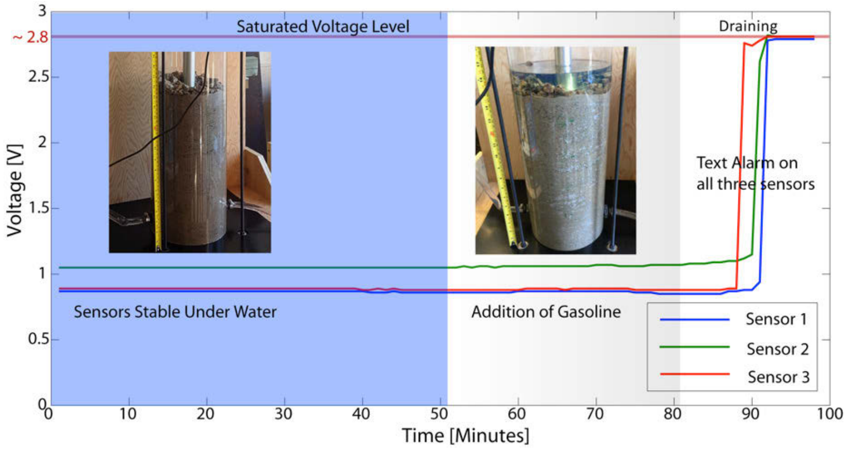


Figure 5: Gasoline exposure

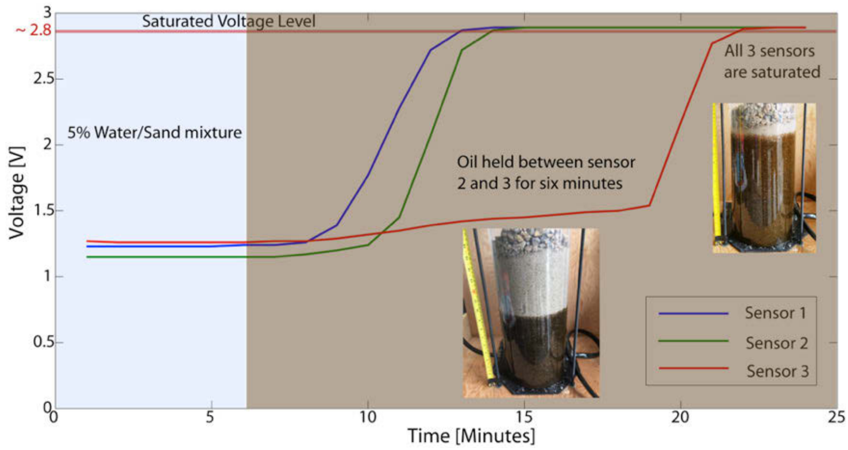


Figure 6: Crude Oil exposure

CONCLUSIONS

- The design and validation testing of the SubSense™ ground probe, a stand-alone, wireless, liquid hydrocarbon leak detection unit is complete.
- The SubSense unit must be installed in the leak path of the liquid since it needs direct contact with a hydrocarbon to trigger.
- Different types of wireless communication can be used within this unit: cellular, satellite and radio.
- The polymer nano-composite sensor employed in this unit is stable even when the sensor is fully submerged in water for long time.
- In independent testing, a large response within one minute for every hydrocarbon tested was observed as soon as the liquid contacted the sensor.
- The algorithm employed for detecting and alarming an exposure to hydrocarbons eliminates most routes to a false positive.
- Text alarms or notifications can be programmed so that the algorithm only alerts for certain types of hydrocarbons allowing for selective detection.

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Steel Pipeline Failure Probability Evaluation Based on In-line Inspection Results

Maciej Witek > GAZ-SYSTEM

Abstract

The main goal of this paper is to estimate onshore buried pipeline failure probability based on Magnetic Flux Leakage (MFL) inspection data. Degradation of an underground steel structures during their service life leads to reduction of the pipe wall thickness. Periodic in-line inspections are performed by grid operators to detect corrosion anomalies and size their depth, length and width. In diagnostics of steel pipelines, it is common practice to track the same flaws in different inspections (i.e. so-called defects matching) based on the longitudinal and circumferential positions of the anomalies reported by applied tools. A code-based engineering approach to estimate the failure pressure was selected as appropriate to be applied directly after in-line inspections, due to the scope of the available data, before any expansive field excavations for direct observations. Det Norske Veritas DNV-RP-F-101 analytical method of burst pressure calculation for a straight pipe was applied. A probabilistic methodology was used to evaluate the severity of part-wall external corrosion defects and their growth over time on gas transmission grid.

The Monte Carlo numerical method was selected in this paper for estimation of pipeline failure probability due to the external corrosion with respect to statistical distribution of input parameters. The predicted flaw depth growth was modeled as non-linear with a power law function parameters derived from literature [1,6,7]. The expected defect length growth rates was forecasted as linear with several scenarios. It was assumed that failure probability of an underground pipeline is influenced only by the growth of the existing features, whereas generation of new defects is neglected. The paper illustrates reliability-based maintenance planning, in the case when a number of anomalies and its statistical distributions are known from MFL in-line inspection. Criteria and formulation of a limit state function were presented to determine the burst pressure and corresponding failure probability of a pipeline DN 700,

X 52 steel grade with amount of 138 fully matched single part-wall defects. The results of this study shall help maintenance engineers to solve the problems of an effective strategy in reliability-based high pressure gas pipelines management.

TIME DEPENDENT METAL LOSS-TYPE DEFECTS ASSESSMENT

The general corrosion of underground steel structures is mostly a consequence of electrochemical oxidation, whereas pitting corrosion is caused by either direct or alternating current at locations of the damaged coating. In the real pipeline maintenance conditions, the corrosion grow rate can be highly variable. Pitting corrosion rates have been found to be much higher than general corrosion rates. The speed of both these corrosion forms tend to be more variable in early pipeline operation time than in later maintenance years. Nevertheless, local conditions of the soil surrounding the pipe and other parameters affect the rates of corrosion, which are continuously varying along the pipeline length. The transmission pipeline can cross different types of soil over long distance. In failure calculations, a soil type would be considered as a variable or the worst case of the soil could be used [1,6,7]. From the steel pipe wall aging process point of view the type and possible damage of coating is also significant as well as detailed issues of cathodic protection system. In real maintenance conditions, the grow of corrosion in axial direction is limited to the area of coting damage, if the insulation is strongly cohesive and is not disbanded. The studies considered in this paper are based on high resolution MFL inspections conducted in years 2000 and 2012 and defect growth rates mean values are derived from diagnostics results. The investigated pipeline was coated with bitumen and commissioned in the year 1986, which means that the diagnostics surveys were conducted not in its early service years and from this reason the electrochemical corrosion rates tend to be stable. The evaluation of the burst pressure of the pipeline as a function of operation time was computed by Monte Carlo method.

A corroding high pressure steel pipeline typically fails by either small leak or burst, due to the internal gas pressure taken into consideration as only one load, mostly as random variable [2,3,5-7]. A small leak occurs if a corrosion penetrates the pipe wall prior to the plastic collapse of the remaining ligament at the defect, due to the internal pressure, whereas a burst occurs if the remaining ligament undergoes plastic collapse before the defect penetrates the pipe wall. In this study, only a pipe burst was considered because the cost of a small leak is much more insignificant compared with potential burst consequences. However, bursts can be further classified as a large leak or a rupture based on whether or not the through-wall flaw resulting from the pipe burst extends unstably in the longitudinal direction [2,3]. Flaws considered in this work have a residual wall thickness bridge before the pipe burst. Det Norske Veritas DNV-RP-F-101 [5,8] engineering approach to estimate the failure pressure is selected to be applied based on in-line inspections data, before any expansive field excavations. The time dependent failure pressure $P_{fDNV}(T)$ of a corroded pipe with a single metal loss without any reinforcement is expressed as:

$$P_{fDNV}\left(T\right)=\frac{2tf_u\left(1-\dfrac{d\left(T\right)}{t}\right)}{\left(D-t\right)\left(1-\dfrac{d\left(T\right)}{tQ\left(T\right)}\right)} \tag{1}$$

where bulging factor $Q(T)$ is calculated from the formula:

$$Q\left(T\right)=\sqrt{1+0.31\left(\frac{L\left(T\right)^2}{Dt}\right)} \tag{2}$$

The localized form of corrosion should be variable in time and the growth rates during maintenance period can be derived from at least two repeated inspections. A similar approach can be found in literature, e.g. [2,3,5]. The generation of new flaws between in-line inspections can be neglected. It means the assumption under which defects initiate at the same time and then grow with the mean value independently of local environmental conditions which are changeable along the pipeline length and the exact soil parameters are not well known. The paper applies a repeated in-line inspections approach to the pipe wall corrosion rate determination using the experimental mean values such as d_{mean} – for defect depth and L_{mean} – for its length. In many studies both an axial (c_L) and a radial corrosion growth (c_d) are assumed for simplicity to be constant over the forecasted period and calculated based on real diagnostics results without considering the accuracies of MFL inspection tool sizing. For a linear model of the corrosion growth applied in publications such as [3-5], an estimated defect depth $d(T)$ and its length $L(T)$ at time T is calculated as:

$$d\left(T\right)=d_{mean}\left(0\right)+c_d\cdot T \tag{3}$$

$$L\left(T\right)=L_{mean}\left(0\right)+c_L\cdot T \tag{4}$$

However, in the current paper, the predicted defect depth growth rate was forecasted as non-linear with a power law function [1,3,6,7] which relates to the average value of the of the corrosion velocity in depth based on inspections data performed on the studied pipeline:

$$d_p\left(T\right)=d_{mean}\left(0\right)+kT^n \tag{5}$$

where:

k - pitting proportionality and n - exponent factor are obtained in literature [1,6,7] by statistical studies. In most studies, k and n coefficients are constant and are assumed based on both variables of the pipe material properties as well as on the parameters of the surrounding soil. Based on estimates of the corrosion growth parameters for typical soil conditions presented in [1, 6], the defects depth power low function parameters were assumed in this paper as follows:

$$d_p(T) = d_{mean}(0) + 0.164 \times T^{0.78} \qquad (6)$$

A defects length growth rate in axial direction was modeled as linear according to equation (4) with following scenarios of corrosion growth rates presented in Figure 2 as a function of time:

Scenario 1 (base) - 1.8 mm/year;
Scenario 2 - 1.0 mm/year;
Scenario 3 - 0.5 mm/year;
Scenario 4 - no defects growth in axial direction.

The metal losses depths have the same corrosion growth rates values for all the considered scenarios, as shown in Figure 1. The inspections tools biases and random scattering errors as well as probability of defects detection are neglected in the current study.

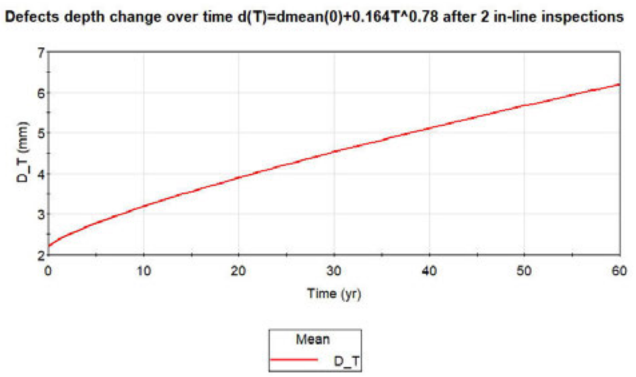

Figure 1:
Defects depth growth rate over time forecasted with a power law function

RELIABILITY FUNCTION

A formula of a limit state function and analytical methodology based on DNV-RP-F-101 [5, 8] criteria is applied to determine the failure pressure of a pipeline with a great number of single metal losses. Similar as in publications e.g. [2-9], a pressure difference formulation of a limit state function and Monte Carlo method were applied for the reliability calculations, due to the corrosion without any pipeline extensive excavations and repairs. Limit state function $g(\vec{X})$, in the case of a pipe affected by a part-wall metal loss, can be expressed as follows:

$$g(\vec{X}) = \overrightarrow{P_{fDNV}} - \overrightarrow{OP_{\max}} \qquad (7)$$

where:
$\overrightarrow{P}_{fDNV}$ – vector of theoretical failure pressures;
$\overrightarrow{OP}_{\max}$ – vector of maximum operating pressure of the pipeline to be applied.

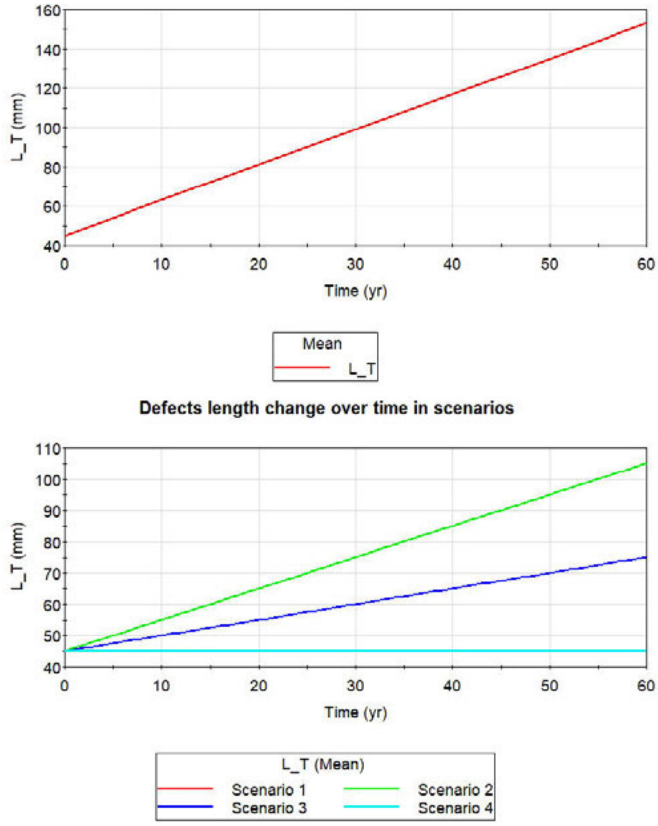

Figure 2a, 2b: Metal losses length growth rates in the axial direction for various scenarios

Failure probability for the corroded pipe as a function of time (T) can be expressed as:

$$P_{fDNV}(T) = P\left[g(\vec{X},T) \le 0\right] = \int_{g(\vec{X}) \le 0} f(x_i,T)\,dx_i \qquad (8)$$

where:

$P_{fDNV}(T)$ – failure pressure of the corroded steel pipe as a function of time, [MPa].

The pipeline failure probability resulting from growing corrosion is determined in the current paper with the use of Monte Carlo (MC) simulation [4-9]. For a specific time period, a numerical simulation is conducted by generating random numbers for variables $\overrightarrow{P}_{fDNV}$ and $\overrightarrow{OP}_{\max}$, with respect to statistical distribution of the input parameters specified in Chapter 3. For each evaluation of the limit state function (7), the occurrence of $g(\vec{X}) < 0$ is counted.

The failure probability of the whole section of pipeline $P_{f\ pipeline}(T)$ at time step T, with the assumption of independence of individual failures of pipes connected in a series is calculated as a function of time $P_{ft}(T)$ according to formula (9):

$$P_{f\ pipeline}(T) = 1 - \prod_{i=1}^{n} \left(1 - P_{fi}(T)\right) \tag{9}$$

where:

$$P_{fi}(T) = \frac{N_f}{N} \tag{10}$$

$P_{ft}(T)$ – failure probability of individual defects at time step T, [-];
n – number of corrosion anomalies based on in-line inspection data, [-];
N – total number of simulation cycles/trials, [-];
Nf – number of failure events which means simulation cycles when $g(\bar{x}) < 0$, [-].

For each external corrosion feature based on the in-line inspection data, the total number of failure events N_f is determined at time step T, after N samples are generated and failure probability of an individual defect can be obtained using equation (10).

The smaller the probability of failure, the larger the sample size is needed in Monte Carlo method to ensure the same calculation accuracy. In this pipeline reliability study, the number of trials was set as 106, which is enough to ensure the accuracy of probability of failure estimation [2-4]. Computations in the current paper were carried out with Goldsim software.

INPUTS DATA EVALUATION FOR RELIABILITY CALCULATIONS

For the inputs parameters specified below, the pipe diameter and wall thickness are modeled as random variables based on pipe manufacturer certificates. The coefficient of variation (COV) of the random variable [X] equals the ratio between standard deviation StD[X] of the measured values and its mean value. The random variables listed below arise from the real diagnostics results. A flaws size growth rate equal the mean value obtained from the inspections data divided by whole 25 years of the pipeline service. A detailed analysis of the diagnostics results can be found in publication [5]. The choice of the Gumbel distribution for operating pressure fluctuations in this paper was based on publications [2-5,7,9]. The maximum operating pressure of studied pipeline is MOP 5.5 MPa and standard deviation computed in [5] from extreme value distribution parameter is equal to s = 0.3. Statistical distributions of all input parameters for the analyzed pipeline reliability calculations are reported in Table 1.

No.	Parameter	Unit	Mean value	Uncertainty Coefficients	Distribution type
1.	Steel yield strength (fy)	MPa	370.6	StD[fy]= 12.2 COV[fy]= 3.3 %	Lognormal
2.	Tensile strength (fu)	MPa	554.7	StD[fu] = 19.4 COV[fu]= 3.5 %	Lognormal
3.	Pipe wall thickness (t)	mm	11.0	StD[t] = 0.5 COV[t] = 4.5 %	Normal
4.	Pipe diameter (D)	mm	711.0	StD[D] = 20.3 COV[D] = 2.8 %	Normal
5.	Maximum operating pressure (MOP)	MPa	5.5	s = 0.3 COV[MOP]= 5.5 %	Gumbel
6.	Defect depth (d)	mm	2.2	StD[d] = 0.6 COV[d] = 26.6 %	Normal
7.	Defect length (L)	mm	45.1	StD[L] = 34.6 COV[L] = 76.9 %	Lognormal
8.	Defect depth growth rate dp(T) as a power law function acc. to equation (5) with parameters n, k	mm/yr	-	-	Parameters n, k fixed/deterministic
9.	Defect length growth rate as a linear function acc. to equation (4) with parameter (cl)	mm/yr	1.8	Scenario 1 (base) - 1.8 mm/year; Scenario 2 -1.0 mm/year; Scenario 3 -0.5 mm/year; Scenario 4 - no defects growth in the axial direction.	Fixed/deterministic

Table 1: Statistical distribution of input parameters for reliability evaluation
Source: Author's analysis [5]

PIPELINE FAILURE PROBABILITY CALCULATIONS

A stochastic chart of the studied pipeline failure pressure over time, due to the growth of defects dimensions d(T), L(T) for scenario 2 as an example, is shown in Figure 3. It can be observed that the burst pressure changes during 60 years of operations starting form the second in-line inspection decreases from 17.5 MPa to 14.5 MPa with a chance of 50%. However, there is also a 1% chance that the failure pressure at the start of pipeline operation period will be in the scope of 11÷15 MPa, and at the end of the considered pipeline life cycle period between 5 and 10 MPa, as it can be shown in Figure 3.

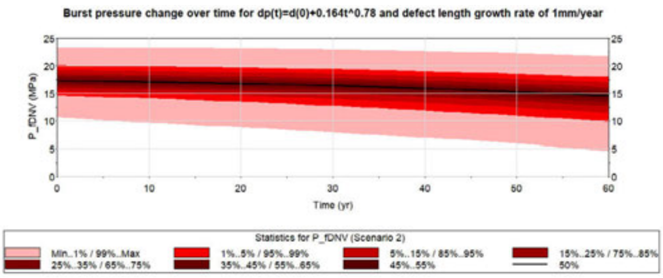

Figure 3: Stochastic burst pressure of the pipeline over time due to the growth of features dimensions d(T), L(T) for scenario 2
Source: Author's calculations

A burst pressure probability density function for scenario 1 at the end of the considered pipeline life cycle period of 60 service years is shown in Figure 4.

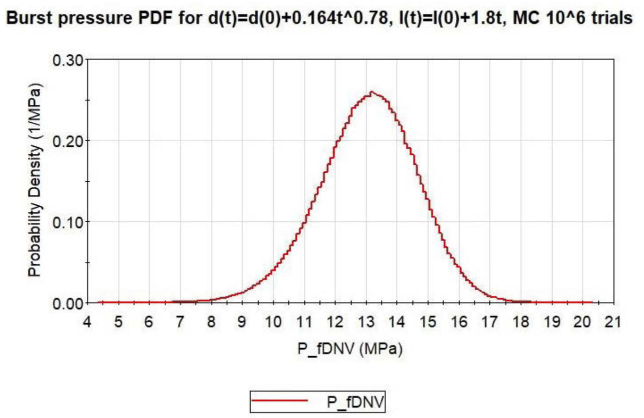

Figure 4: Burst pressure probability density function for scenario 1
Source: Author's calculations

For the same corrosion velocity in depth, the smaller defect length grow rates assumed for scenarios 2-4 the higher pipeline burst pressure capacities whose distributions are presented in Figure 5. For the same forecasted corrosion in depth, the overall failure probability for scenario 1 has also the highest value compare to the burst probabilities for lower corrosion growth rates in axial direction. Burst pressure change of the pipeline during the service period depends significantly on a defects length growth rate. Computations of failure pressure of the studied pipeline showed that the active pipe wall corrosion defects lie within the acceptable values for the foreseen operating conditions characterised by various parameters surveyed in the current paper.

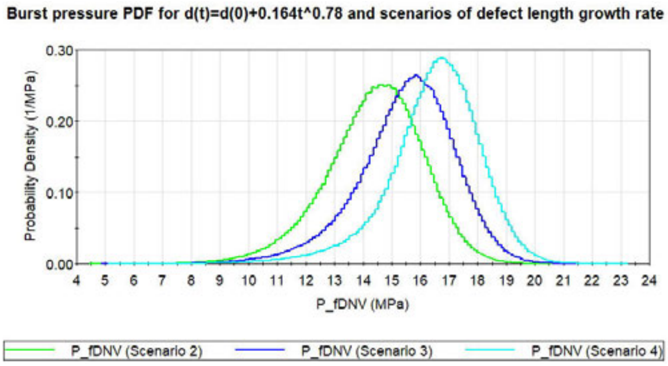

Figure 5: Failure pressure probability density function for various defects length grow rates corresponding to Figure 2
Source: Author's calculations

The failure probability over a life cycle of 60 years for the features depth and anomalies length considered in this paper are presented in Figures 6 and 7 as well in a logarithmic scale in Figure 8. The calculated failure probabilities over 60 years of pipeline maintenance starting from the second inspection, even for non-reinforced defected pipes, are very low and remain lower than a related code-based target value for a so-called normal safety class set in [8] as not higher than 10^{-4} per annum.

For a high safety class characterised by frequent and intensive human activity in the pipeline souranding area, the target annual failure probability is set as not exeeding 10^{-5} per annum. For the studied pipeline it means that for scenario 1, after 55th year started from the second diagnostics, the most significant defects need to be repaired due to crossing the target code based probability of failure [8]. For scenario 2, the target failure probability is reached in the 59th year of pipeline operation, as it can be seen from Figures 7 and 8.

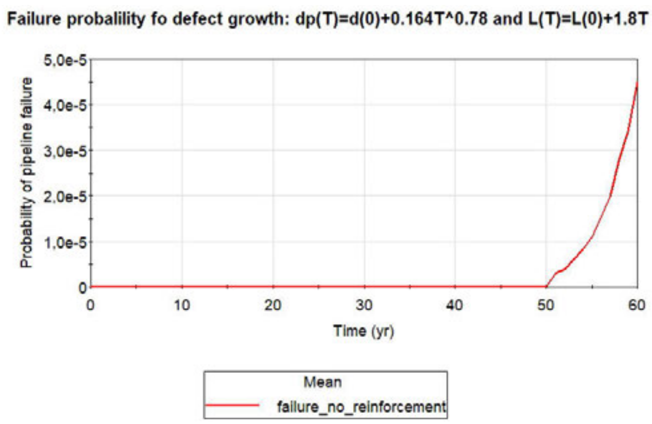

Figure 6: Probability of failure over 60-year pipeline maintenance for the defects depth and their length corresponding to the base scenario
Source: Author's calculations

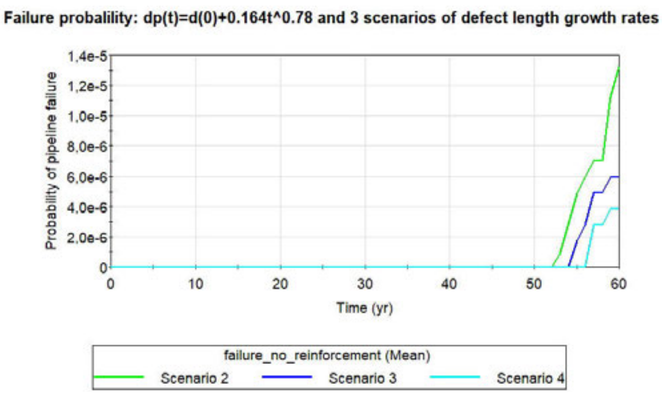

Figure 7: Probability of failure over 60-year pipeline maintenance for the feature depth and anomaly length corresponding to the data in Figure 5
Source: Author's calculations

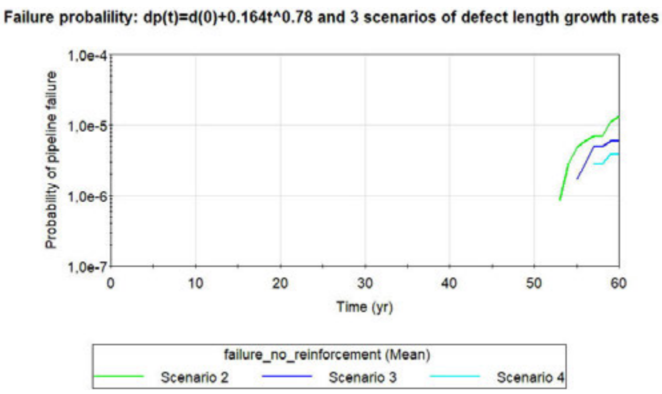

Figure 8: Logarithmic chat of failure probability over 60-year pipeline maintenance for the defect depth and its length corresponding to the data in Figure 5
Source: Author's calculations

CONCLUSIONS

Burst pressure of a steel pipeline was calculated in this paper according to DNV-RP-F101 methodology using the real two repeated diagnostic results, without any field excavations for direct assessment. For an underground gas transmission pipeline DN 700 constructed in the year 1986 from steel grade equivalent to X52, the flaws detected with MFL tools were evaluated by means of statistical methods.

A burst pressure change of the pipeline during the service period depends significantly on a metal loss length growth rate as well as on the predicted defect depth increase. Computations of failure pressure of the analyzed pipeline showed that the active corrosion defects lie within the acceptable dimensions for the foreseen operating conditions characterised by various parameters surveyed in the current paper.

The calculated failure probability over 60 years of pipeline service starting from the second in-line inspection, even for non-repaired defected pipes, are very low and remain lower than a related code-based target value set for a normal safety class as not higher than 10^{-4} per annum. In the later maintenance years, e.g. after studied pipeline operation life exceeding 50 years a rate of the failure probability increase is strong, which means the rapid aging process of steel underground structure.

The employed method is a technique of reliability control and extension of the remaining service life of the corroded pipelines. The applied methodology can be helpful for selection of the optimal inspection intervals for steel pipelines to maintain the failure probability within acceptable values as well as can be also used in defects repairs decisions.

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Assessing Repeat ILI Data Using Signal-to-Signal Comparison Techniques

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Abstract

For pipelines with successive ILI runs the detected population of corrosion defects can be compared to identify both internal and external corrosion growth. Depending on the number of defects to be compared, the assessment can demand significant effort and expertise to ensure accurate and meaningful correlations between often very large ILI data sets. Specialist ILI comparison software facilitates efficient and accurate signal-to-signal matching and the determination of defect specific growth rates across very high defect populations. However, since ILI as a measuring technique is subject to inherent uncertainties, the prediction of where corrosion is active and the rate of growth from consecutive ILI runs also has a degree of uncertainty. The level of uncertainty is influenced by several sources of error:

- The ability to accurately match the metal loss sites between the two ILI data sets
- Identification of measurement bias associated with the ILI tools
- Understanding the repeatability errors between the two ILI tools

There are various approaches that are used to compensate for these inherent errors. For instance, there are different ILI data matching methods that can be used and depending on the level of precision employed and the input data available these will result in varying levels of accuracy. We state signal-to-signal matching is the most precise and accurate approach that can be used over other methods such as box matching, but is there a common understanding of what “signal-to-signal matching” means, what information is required to perform it, what are the ways it can be done and the relative merits? This paper focuses on these questions in relation to comparing magnetic ILI tool data and looks at the challenges for signal matching across magnetic ILI tools with differing resolutions and even from different vendors. In addition, we discuss the importance of understanding tool bias and repeatability and minimizing the impact of these errors.

INTRODUCTION

Corrosion is considered a major threat to the integrity of many onshore and offshore, gas and liquid pipelines. In the presence of water (from either the product or the external environment) unprotected carbon steel will corrode. Corrosion can affect the load carrying capability of a pipeline and, if it continues to grow, it will result in either a leak or rupture release when it reaches critical dimensions for the pipeline.

The first line of defence against corrosion damage is by the primary corrosion control systems, e.g., the pipe coating, cathodic protection and by chemical treatments and/or water removal for internal corrosion. However, with time these primary control systems often deteriorate or fail and the pipeline operator must be able to identify the location and severity of corrosion activity to determine how quickly the integrity of the pipeline is deteriorating.

The accurate estimation of the rate of corrosion growth in a pipeline is a key consideration in the development of effective Integrity Management Programs. The determination of the need for, as well as the location and timing of mitigative or preventive measures such as CP upgrades, coating repairs, pipe repairs and chemical treatment programs for pipelines carrying corrosive products all depend on assumptions about the rate of corrosion growth. Also, decisions on the re-inspection interval for the pipeline need to consider the remaining life of the un-investigated corrosion defects.

Many pipelines have now been inspected using intelligent in-line inspection (ILI) tools several times. Using these repeat ILI data sets to determine corrosion growth rates is now an established and recognized best practice with pipeline operators. Depending on the number of defects to be compared, the assessment can demand significant effort and expertise to ensure accurate and meaningful correlations between often very large ILI data sets.

There are different ILI data matching methods that can be used and depending on the level of precision employed and the input data available these will result in varying levels of accuracy. In the following sections, this paper discusses the challenges associated with the different ILI data matching and comparison methods and the inherent uncertainties in the resulting corrosion growth rates obtained. The paper focusses on the comparison of magnetic flux leakage ILI data.

> *"This Paper considers the challenges for signal matching across magnetic ILI tools with differing resolutions and/or from different vendors.*
> *Jane Dawson*

ILI BASED CORROSION GROWTH RATES

Since the general introduction of ILI techniques in the 1980's and the broad adoption by most operators by the 1990's/2000's (for transmission pipelines at least) ILI has become the commonly used method for determining where on a pipeline corrosion is occurring and the dimensions of the corrosion. The advance of technology in this field has resulted in the availability of many types of ILI technology to cater for the large range of pipeline sizes, product types, internal restrictions, the different forms of pipeline defects that can occur and the ever-present drive to categorize defect types and predict dimensions more accurately. When there is more than one ILI run for estimating the corrosion growth rates it is now commonplace to compare the two ILI defect populations to estimate the rate of corrosion growth based on defect-to-defect matching. The significant advantage over other methods is that ILI can provide size and growth rate information on the overall detectable defect population giving visibility of what is happening along the entire pipeline.

For pipelines with successive ILI runs the detected population of corrosion defects can be compared to identify both internal and external corrosion growth. Depending on the number of defects to be compared, the assessment can demand significant effort and expertise to ensure accurate and meaningful correlations between often very large ILI data sets. Specialist ILI comparison software facilitates efficient and accurate defect-to-defect matching and the depth comparison to determine the defect specific growth between the two runs across the large ILI defect populations. However, since ILI as a measuring technique is subject to inherent uncertainties, the prediction of corrosion rates from consecutive ILI runs also has a degree of uncertainty.

When comparing two sets of ILI data there are two main sources of error [1,2]. Firstly, error introduced due to inaccurate matching of corrosion sites and secondly inaccuracies associated with the growth measurement. The growth measurement error consists of two parts; a bias (a systemic difference in the prediction of defect depth and is not associated with growth) and a scatter (represented by the tool repeatability error). The tool repeatability error can be obtained from repeated measurements of the same set of defects under the same conditions. The effect of bias and the repeatability error can be minimized by using the same ILI tool technology and vendor for both runs (following calibration of the ILI signal data for different levels of magnetization any bias present will be repeatable in both runs and essentially cancels out).

There are several matching techniques that can be used; cluster matching, box matching or signal matching [3]. All three methods involve defect-to-defect matching with varying levels of accuracy as discussed below:

2.1 Cluster Matching and Box Matching

A comparison of the reported clusters in the pipeline listing from each ILI run can be made by aligning the girth weld numbers, relative distances and orientation of the clusters. However, as illustrated in Figure 1, new clusters reported in the second run can make accurate matching of clusters difficult. If the correct clusters are not matched then this leads to errors in the calculation of corrosion growth rates. Also, there are other errors inherent in cluster matching. The reported ILI cluster will be represented by a maximum depth and total axial length even though it could be comprised of multiple corrosion pits of varying dimensions. By comparing the overall cluster dimensions rather than the individual pit dimensions the resulting corrosion growth rate may under-estimate the actual growth (see Figure 2). In addition, different ILI vendors report the cluster position differently (some report distance to start of cluster, others to mid-point or max depth position) adding additional complexities to align clusters from 2 x ILI's. Cluster matching is the least favoured method for determining corrosion growth rates from repeat ILI data due to the increased likelihood of data matching errors and lack of precision.

The principle of box matching is demonstrated in Figure 2. If the boxes are available from the ILI vendor, then these

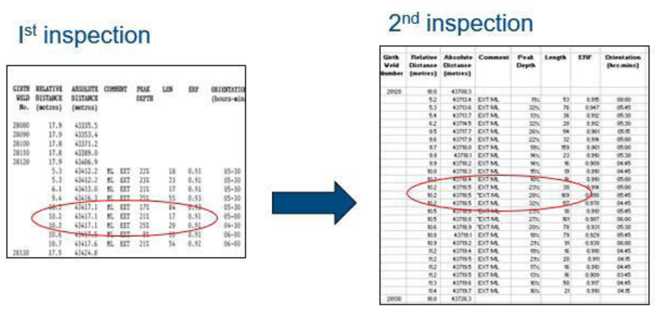

Figure 1: Example of Cluster Matching

Figure 2: Example of Box Matching

can be aligned and matched between the two inspections. Box matching removes one of the main errors associated with cluster matching, which is the assumption that the deepest individual corrosion defect is at the same location in both inspection runs. However, in the example in Figure 2, the deepest defect in the old survey is at a different location from the deepest defect in the new survey. Therefore, when conducting the calculation of corrosion rates based on cluster matching, the corrosion rate would be under estimated. This figure also illustrates how the boxing and clustering may change between inspections due to sites of corrosion being detected differently or new corrosion occurring between runs.

Although box matching allows some of the data matching errors associated with cluster matching to be reduced, it can still be difficult to ensure that accurate matches are made between boxes, especially where areas of complex corrosion exist.

The box matching approach tends to be used mainly where different ILI vendor data is being compared. In this scenario, the growth error can still be significant as both bias and tool measurement errors are contributing to the overall growth error.

2.2 Signal Matching

The Signal matching approach is illustrated in Figure 3. This is proven to be the most accurate method of comparing repeat ILI data sets. Clearly, the more detail that is available the more accurate the matching of the ILI data and hence it is obvious that signal matching will provide the best matching result.

Hence, we state signal-to-signal matching is the most precise and accurate approach that can be used over other the methods, i.e., cluster matching and box matching, but is there a common understanding of what "signal-to-signal matching" means, what information is required to perform it, what are the ways it can be done and the relative merits?

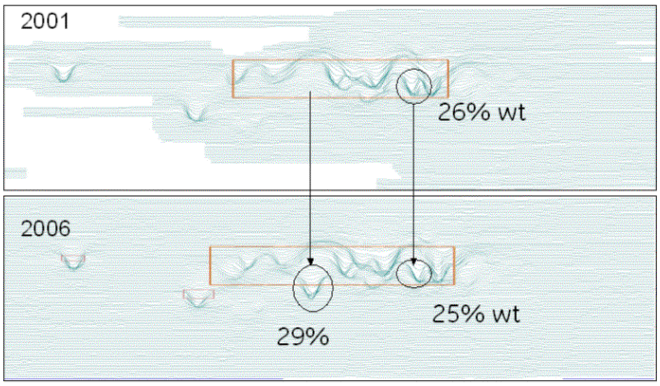

Figure 3: Example of Signal Matching

As the name suggests, signal matching involves matching the defects via a direct alignment and comparison of the ILI signal data. Hence, the signal data from both ILI runs is required to facilitate the matching process. The signal data can be accessed via the vendor's proprietary ILI viewing software, however, if different vendor signal data is being compared this can be problematic as different signal conventions are often used by different vendors for representing the ILI data, e.g., metal loss/metal gain may be represented as a negative signal/positive signal direction and there is not a common format used. Hence, signal matching should only be attempted by a person trained in ILI signal analysis and is best left to the ILI vendor.

Furthermore, as discussed earlier, inaccurate, matching is not the only source of error in the growth assessment process and the inaccuracies associated with the growth estimation itself introduces other errors. The growth error is made up of two parts; a bias associated with the estimation of the defect depth and a scatter representing the tool repeatability error. The effect of bias and the repeatability error can be minimized by using the same ILI tool technology and vendor for both runs. The direct comparison of the ILI signals and the use of signal scaling or calibration techniques minimise the errors (bias is eliminated and repeatability error is much smaller than the measurement error associated with the individual two tool runs).

This approach should be referred to as "Signal matching WITH signal calibration" as it has the added step of the detailed signal calibration and comparison to minimise the growth error. This second step is very difficult to perform meaningfully on different ILI vendor data for the following reasons:

i. Different ILI vendor tools will have different ILI tool resolution e.g., high accuracy/detection vs low accuracy/detection for pinholes. These differences can result in false growth calculations.
ii. Differences in the ILI tool magnetic field strength (high vs low field) will lead to different accuracies/detection for lower level defects.
iii. Different ILI vendors use different signal conventions for representing the ILI signal data, e.g., metal loss/metal gain may be represented as a negative signal/positive signal direction.
iv. Different signal modelling approaches e.g., symmetrical vs asymmetrical specifications for sizing accuracy.
v. Time based vs distance based sampling will lead to differences in the magnetic signal.
vi. Thick wall speed effects are highly dependent on length of magnet return path which may be completely different between tools. i.e., difficulties in calibrating the signal data.
vii. Repeatability errors are difficult to quantify (as these are usually determined by statistically analysing repeated pull-through test data) which is not available for vendor 1 vs vendor 2 data.

Hence, when comparing ILI data from different vendors it is more difficult to reduce the growth errors to the same extent. Signal matching can still be performed to minimise the data matching errors either manually on selected locations or along the full pipeline using software capable of such precise matching from the different data sources. But conducting the detailed signal comparison to minimise the growth error is difficult to perform meaningfully on different ILI vendor data for the reasons discussed above.

So, there are clearly two "signal matching" approaches that tend to be used; these differ based on whether the two ILI data sets belong to the same vendor (and same technology) or are different vendor data. These approaches are described in the following table:

Different types of Signal Matching Available for the Same and Different ILI Vendor Data Comparisons		
	ILI Vendor X (Previous run)	ILI Vendor Y (Previous run)
ILI Vendor X (Current run)	Signal matching for data alignment. Signal scaling/calibration for depth comparison and growth determination. Repeatability error calculation for growth certainty.	Signal matching for alignment and defect matching. Comparison of reported box depths for growth determination.

Table 1:
Different Types of Signal Matching Available Depending on ILI Data Sources

Assuming that similar magnetic flux leakage technologies are being compared.

When a corrosion growth assessment is being conducted it is important to decide firstly what level of ILI comparison is possible with the two ILI data sets, what level of accuracy is required.

We've introduced the concept of the growth error in a ILI data comparison, this is described in more detail in the following section.

GROWTH ERROR

Growth Rate Calculation

The basic equation used to calculate corrosion growth rate, R, is:

$$R = (X_2 - X_1)/t \tag{i}$$

where X_1 and X_2 are the corrosion depths at the time of the first and second ILI inspections, and t is the time between inspections. It is noted that this equation calculates the average growth rate over the time interval between ILI runs. It does not capture growth rate variations within that time interval, which could result from changes in the conditions that drive corrosion.

Each of X_1 and X_2 is characterized on the basis of a single measurement, x_{m1} and x_{m2}.Because of measurement error, the actual values of X_1 and X_2 given the measurement are treated as uncertain (or random) variables. Since R is calculated from X_1 and X_2, it also is a random variable. Note that an upper case symbol (e.g. X or R) is used to represent a random variable that can assume a range of values, whereas a lower case symbol (e.g. x or r) is used to represent a specific value assumed by the random variable. This is standard probability notation.

3.2 Effect of Growth Measurement Uncertainty

As discussed earlier in this paper, the growth measurement error (or repeatability error) has two components: a bias that changes from defect to defect (due to differences in conditions between defects) and a scatter representing random variations in measurements made under the same conditions. The scatter is represented by the measurement standard deviation that would be obtained from repeated measurements of the same defect under the same conditions. The bias for a given defect equals the difference between the mean of these measurements and the actual size of the defect. The bias is typically uncertain for different defects and is therefore added to the total uncertainty associated with measurement error.

The term "growth error" is used to represent the uncertainty regarding the total growth between the two ILI runs (i.e. the error in $X_2 - X_1$). It is a result of the non-repeatable (or independent) portion of the measurement error for the individual runs.

If σ_1 and σ_2 represent the standard deviations of the non-repeatable portion of the measurement error for X_1 and X_2, it can be shown that the standard deviation, σ, of the growth error is given by:

$$\sigma = \sqrt{\sigma_1^{\,2}\sigma_2^{\,2}} \tag{ii}$$

The magnitude of both σ_1 and σ_2 depends on how much of the measurement bias for a given defect is repeatable between the two runs. This in turn depends on a number of factors including ILI tool differences, analysis techniques used and also on the types (morphology) of the defects present. Clearly the data repeatability will be lower and the bias higher when comparing different ILI vendor data whereas when comparing the same vendor ILI data, the repeatability will be high and the bias minimal.

There are two scenarios to consider when determining the growth error σ :

1. Only scatter contributes to growth error (σ1 and σ2 represent scatter only). This is applicable if the total bias is identical for the two runs, which is representative if the same vendor data is used in both ILI runs and the analysis method used can identify and eliminating bias.
2. Total measurement error contributes to growth error (σ_1 and σ_2 represent the total measurement error). This is applicable if the bias is completely independent for the two runs, which is representative if two different tools are used, and conservative if there is partial correlation between the bias values for the two runs.

It is also possible to estimate σ directly as the standard deviation of data representing the difference between pairs of measurements of the same defect under conditions that are representative of two consecutive ILI runs, e.g., in pull-through testing. In this case, repeatable bias is eliminated by subtracting the two measurements, and σ is estimated directly. It is also possible to estimate σ directly from a direct comparison of the "static" defects present in the two tool runs and calculation of the standard deviation of the differences between the pairs of defect measurements. The "static" defects are defects that would not change between ILI runs (e.g. mill faults and internal metal loss defects in a pipeline transporting a non-corrosive product such as dry natural gas).

For example, based on a standard MFL tool resolution where the 80% certainty depth sizing tolerance is ±10%wt the growth error (also at a certainty level of 80%) is:

1. ±4.6%wt* when comparing ILI signal data of the same ILI technology and vendor (this value is validated using pull-through testing data),

and

2. ±11%wt* when comparing independent ILI signal data from different ILI vendors (equation (ii) is used to calculate this value).

* Note that these values are calculated using two-sided normal probability distributions. The growth errors will increase at higher levels of certainty e.g., for 90% and 95% levels of confidence in the growth error and will be lower for higher certainty levels of depth sizing tolerance (when comparing different vendor data).

Identifying the Likelihood of Active Corrosion

When the ILI signal data is comparable (i.e., usually when the same ILI vendor/technology has been used in both runs) a visual comparison of the signal data will provide a first qualitative identification of a change to the metal loss between the ILI's and/or the occurrence of new sites of metal loss.

The growth error (i.e., repeatability) can be used to define the level of statistical certainty that an observed growth is "real" and is not due to minor differences in detection/measurement between the two ILI runs. A threshold level can be set using a one-sided normal probability distribution and for a selected statistical certainty level (e.g., 80%, 90%, 95%) above which the observed change is deemed to be associated with "active" corrosion. Where a change is below the threshold it does not mean that this is not necessarily active but that we have less certainty that the change is real growth.

It is highlighted that the growth error (repeatability) will be different for different ILI tools. It varies based on tool size, tool sensor resolution, type, wall thickness, tool speed and also defect type can have an effect. When comparing different vendor ILI signal data, the repeatability threshold is a much higher value (less desirable), it is calculated statistically using the sizing tolerances of each tool as discussed above (i.e., for different vendor data).

In addition to using depth repeatability, a "signal test" has been developed by BHGE that provides additional information whether each individual corrosion is deemed to be active (growing) or not. This test compares the MFL signal characteristics, from the two inspections completed using defined types of tools, at each matched anomaly to provide a classification of growing or not, independent of the depth (or depth repeatability). The process was developed by incorporating a machine learning approach to a large sample set of both unchanged and grown metal loss anomalies to design a test that can be applied, with a specified certainty, to each identified matched metal loss. This provides an operator with confidence that a growth anomaly being excavated is truly growing and can also be used to reduce unnecessary excavations.

ACKNOWLEDGMENTS

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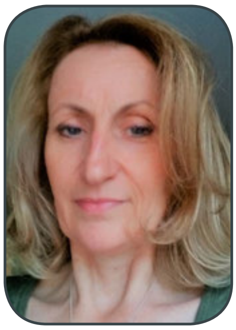

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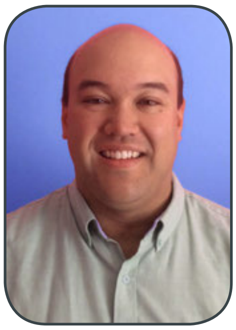

Condition Assessment for Optimizing Gasunie's Network Improvement Program (GNIP)

Martin Hommes; Karen van Bloemendaal; Roelof Coster; Maurice Gielisse > DNV GL
Martin van Agteren; E.E.R. Jager > Gasunie Transport Services

Abstract

The 40 bar regional gas transportation network of Gasunie Transport Services (GTS) consists of, in addition to pipelines, valve stations, pressure regulating and metering stations and gas receiving stations. The majority of these stations have been built in the period 1960-1980. This raises questions on the remaining technical life-time of these stations and adequate measures to comply with safety and transport standards in the future. Gasunie has developed the Gasunie Network Improvement Program (GNIP) in which replacement of these assets is carried out, prioritised on their expected condition.

Gasunie use the Deming circle in order to identify lessons learnt from executing GNIP and verification thereof in the GNIP Verification Project (GVP). In the GVP, life-time critical parts of the replaced stations are inspected, in situ as well as in laboratories, in order to assess their actual condition. Lessons learnt and results from the GVP have led to adjustments in the program in terms of scope and pace. DNV GL has supported Gasunie with developing the GVP, has analysed all GVP results and recommended adjustments both for GNIP and GVP.

This paper gives first, as an introduction, a general overview of GNIP and GVP. Secondly, the results of the GVP will be presented with a focus on the integrity of valve stations and more specifically the design wall thickness of and the depth of corrosion defects found on D&S piping. Thirdly, the actions Gasunie has taken based on the GVP outcomes will be discussed.

INTRODUCTION

The Dutch natural gas industry was founded in the sixties of the previous century, upon the discovery of the large Groningen reserve. Since then, Gasunie's high and medium pressure transmission networks have been extended and adapted to continue meeting changing (market driven) requirements. Therefore, significant parts of the networks are now already approximately 50 years old. Gasunie performed BowTie risk assessments to identify risks related to natural gas transmission pipelines. In these risk analyses, integrity, safety and other risks were identified forageing assets that may affect safe and reliable natural gas transmission.

The findings from these BowTie risk assessments resulted in a decision to initiate the Gasunie Network Improvement Program (GNIP) for the regional 40 bar network. In this programme, three types of stations are subject to profound maintenance in the coming 15 to 20 years.

A complete renovation is the most significant measure, which in general is the case for valve stations. The three types of stations are:

- Below ground valve stations;
- Metering and pressure regulating stations;
- Gas delivery stations[1].

GNIP can therefore be seen as a large scale, coherent bundling of preventative maintenance. The set-up and timing of the program are based on a risk-based prioritization of assets, determining the order in which they are replaced. This way, planning and execution can be continuously monitored and, where possible or required, adapted by for example an increase or decrease of replacement rate or a change of prioritising order. To this end, the program includes a GNIP Verification Project (GVP), in which the integrity status of removed assets is assessed, thus closing a Plan-Do-Check-Act or Deming circle, as shown in Figure 1.

The verification project is executed in yearly batches. During the replacement, the assets at the locations are inspected by specialised companies in different stages, see section approach for more details. In the final stage of the GVP, all results are collected, analysed and combined with data from the asset database, in order to assess the (integrity) status of the replaced objects.

The resulting findings and recommendations are fed back into the risk assessments, into the planning and set-up of GNIP, and back into the set-up and execution of the verification project itself.

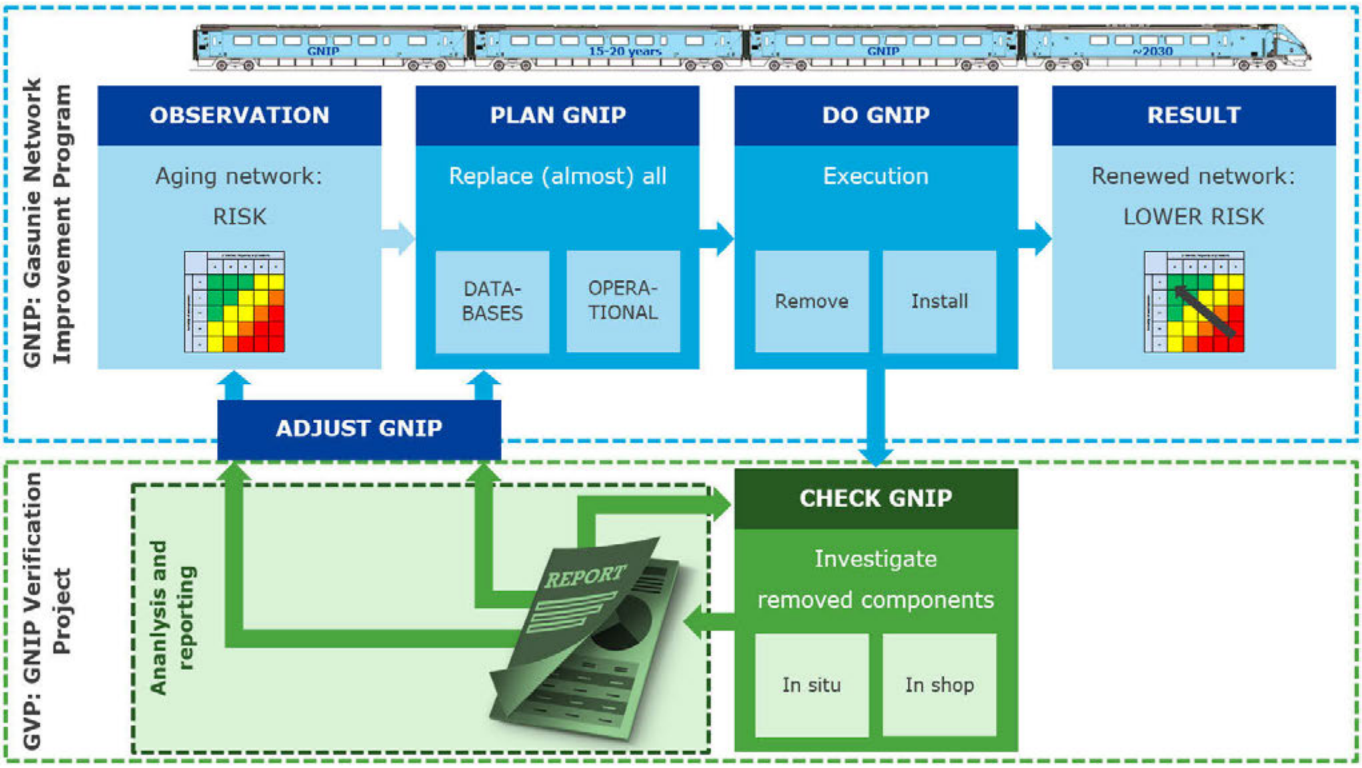

Figure 1: Plan-Do Check-Act-Circle formed by GNIP and the GVP

Figure 2: Example of an below ground valve of a valve location in Gasunie's medium pressure network

The condition of the D&S piping is relevant for safety, but after decades of service buried in the ground, the condition of this piping is unknown. Corrosion of D&S piping is the most relevant threat. It may eventually lead to pinholes, causing natural gas to leak and accumulate inside the valve pit, worst case resulting in an explosion. In addition to that, possible corrosion may decrease the strength of a D&S pipe, increasing the risk of breaking it when the valve is operated by field technicians. Both the design or original wall thickness (strength) of a D&S pipe and the occurrence and depth of corrosion, play a role in the safety risk.

Firstly, the design wall thickness is unknown, nor can it be verified from original drawings or manufacturer's specifications. Generally, the wall thickness of the D&S piping is relatively small and it is known that a share of the older valves may have D&S piping with a design wall thickness that is lower than the current minimum required design wall thickness.

The year 1990 is important, as at that time, Gasunie's specifications regarding this aspect were updated. Secondly, the occurrence and amount of corrosion on aged D&S piping is unknown, and these cannot be verified easily in the field.

The two main preventive barriers for D&S piping to prevent corrosion are the application of protective coating(s) and maintaining cathodic protection (CP). Protective coating may be in perfect condition, but may also have been initially applied insufficiently, may have been damaged at some point in time, may have been needing repair after valve maintenance activities and/or may have deteriorated over the years. It is unknown what the present-day condition of the D&S piping coating is. Furthermore, for most valves, it is difficult to collect detailed information available about the exact functioning history of the cathodic protection system over the years.

In the GVP project, 146 valves stations have been analysed, comprising of 923 valves and 919 D&S pipes thereof.

This article focuses on the replacement of one of the three types of stations: the valve stations. In the medium pressure network, valve stations are used for either sectioning or connecting pipeline routes or for close-in of for example gas delivery stations. These valve stations are typically built below ground. Each valve station consists of several main and bypass valves of different sizes, makes and models. Each valve is placed in a protective tube, capped with an in-street or in-field cover, providing access for operation and maintenance. Figure 2 shows an example of a below ground valve. Valve functionality, i.e. to prevent flow of natural gas from one end to the other, is also investigated in the GVP, but not discussed in this paper.

SCOPE

The original BowTie risk assessments revealed that in general, the design of the valve bodies is sufficiently robust and therefore no major integrity problems are foreseen in the bodies for another couple of decades.

The most integrity-sensitive items of the valves are the drain and sealant (D&S) piping that are located upon or inside the valves. There are several types of D&S piping that are used to drain any liquids from the valve, inject either internally or externally a high viscous sealant or grease to the valve seats or inject a lubricant to moving parts.

APPROACH

The GVP has four stages, which generate data for analysing the condition of valve stations in general and D&S piping in particular:

- In-situ visual inspection while the valve station is still operational and the replacement project has not started;
- In-situ visual inspection when the valves have been excavated and therefore all components can be visually inspected, but have not been removed;
- Visual inspection at the company that cleans the D&S piping and removes the coating;
- In-shop investigation of the removed and cleaned components at the inspection company, with accurate measurements of the wall thickness and the depth of corrosion defects.

The results for each valve station include the following:

- Valve station, valve number, type of D&S piping, inspection date and inspector: these are all used for traceability of the results;
- Condition of each D&S pipe, including coating type and condition, design wall thickness, presence of any corrosion defects, if any, with related depth and location either aboveground or below ground. De aboveground or below ground location is relevant in order to determine if corrosion defects are protected by CP or not. During the inspection, special focus is given to the condition of the potential presence of welding, clamps, connections and joining to non-carbon steel materials, mainly stainless steel;
- General comments for any additional relevant observations as identified by the inspector.

RESULTS

Figure 3 provides examples of the empirical statistical distributions or histograms of the design wall thickness of externally mounted sealant pipes, including the minimum required design wall thickness. A distinction is made between piping originating from valves installed prior to and after 1990. These graphs show that most of the sealant pipes have a design wall thickness exceeding the current minimum required design wall thickness of 2.5 mm. However, there are a total of 27 observations lower than the minimum required design wall thickness, almost all of them originating from valves that were installed prior to 1990. Based on this observation, valve stations installed before 1991 should be prioritised for replacement. Similar statistical distributions are available for the other types of D&S piping: drain pipes and internal sealant pipes.

Figure 4 shows the empirical statistical distribution of the corrosion rate of all external D&S pipes, i.e. drain and external sealant pipes combined. The corrosion rate for each D&S pipe is determined by assuming that corrosion started in the year of installation and that the corrosion rate was constant for the whole life-time.

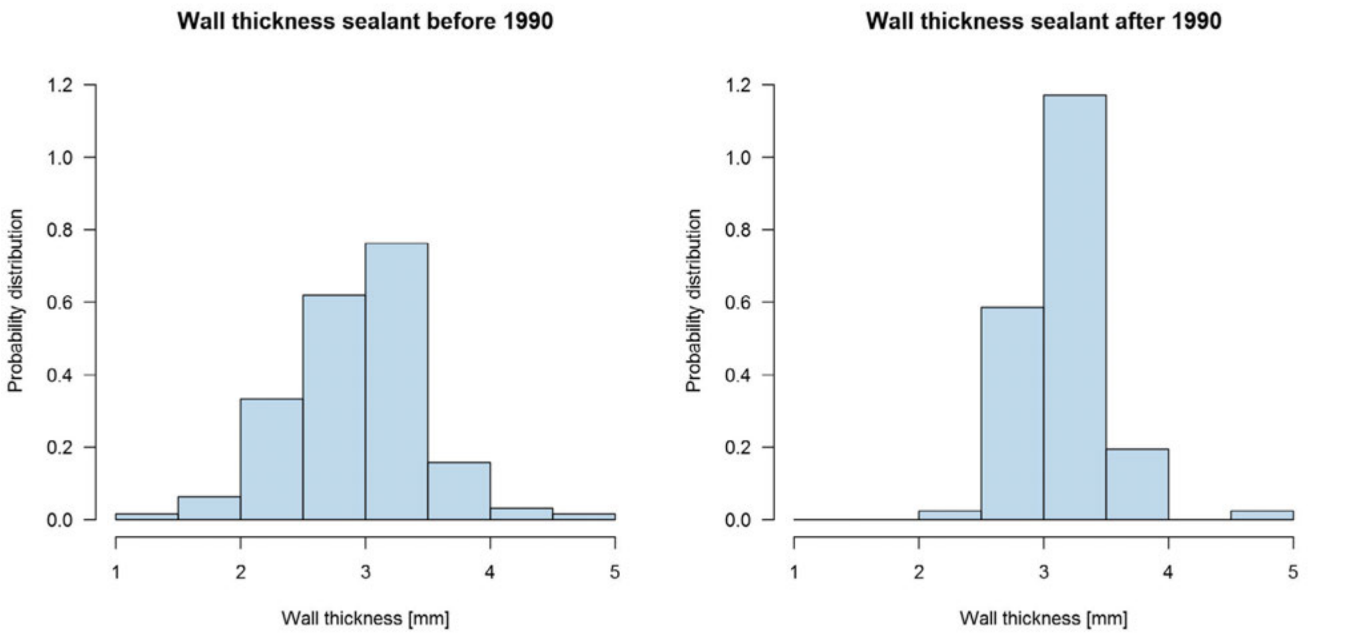

Figure 3: Design wall thickness of sealant piping, installed prior (left) to and after 1990 (right)

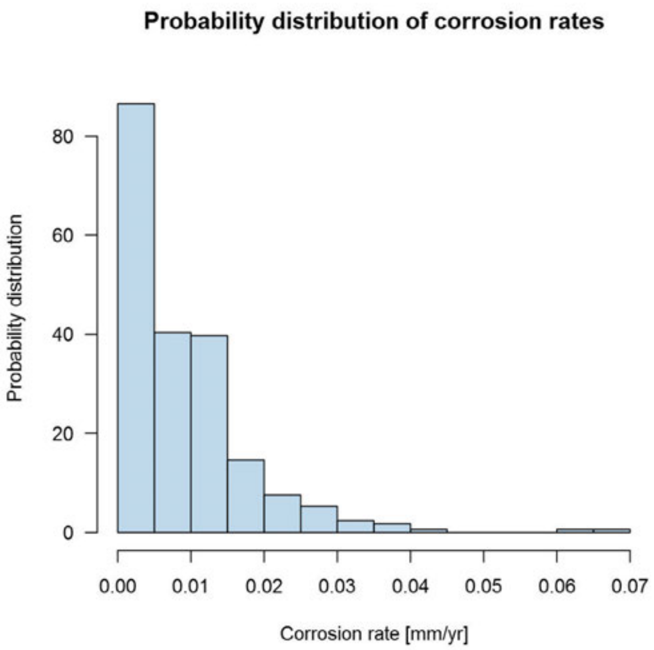

Figure 4: Probability distribution of corrosion rates

A similar statistical distribution is available for internal sealant pipes that are not exposed to the external environment as are external D&S piping and do not have protective coatings nor are protected by CP.

RISK MODEL

A risk model is used to determine the probability of failure of a D&S pipe, i.e. the risk of incidents with loss of containment. The annual replacement rate of valve stations can be adjusted based on the reduction on the probability of failure of D&S piping due to the replacement of valve stations. The moment the corrosion depth is equal to the wall thickness is defined as 'pipe failure' or leakage. This model is based on the probability of failure of D&S piping as a function of age and design wall thickness. Under the fundamental assumption that the corrosion rate and the design wall thickness of the piping are independent of each other, an age-dependent probability of failure of D&S piping can be calculated from the empirical statistical distributions for these parameters. Consecutively, a probability distribution of the time to failure of any pipe can be calculated through a Monte-Carlo procedure. A Monte-Carlo procedure repeatedly calculates the resulting time to failure for each D&S pipe with a design wall thickness and a corrosion rate that both are randomly drawn from the empirical statistical distributions.

Figure 5 shows the resulting probability of failure curves for the sealant piping as function of the year or installation with 10.000 samples[2].

A valve station failure is defined as the first failure of one of its D&S pipes. The expected number of station failures over time across the entire Gasunie network can be determined based on the following data from the Gasunie asset register:

- The number, make, model and year of installation of valves per valve station;
- The numbers and types of D&S pipes per valve;
- The probability of failure for each type of D&S pipe.

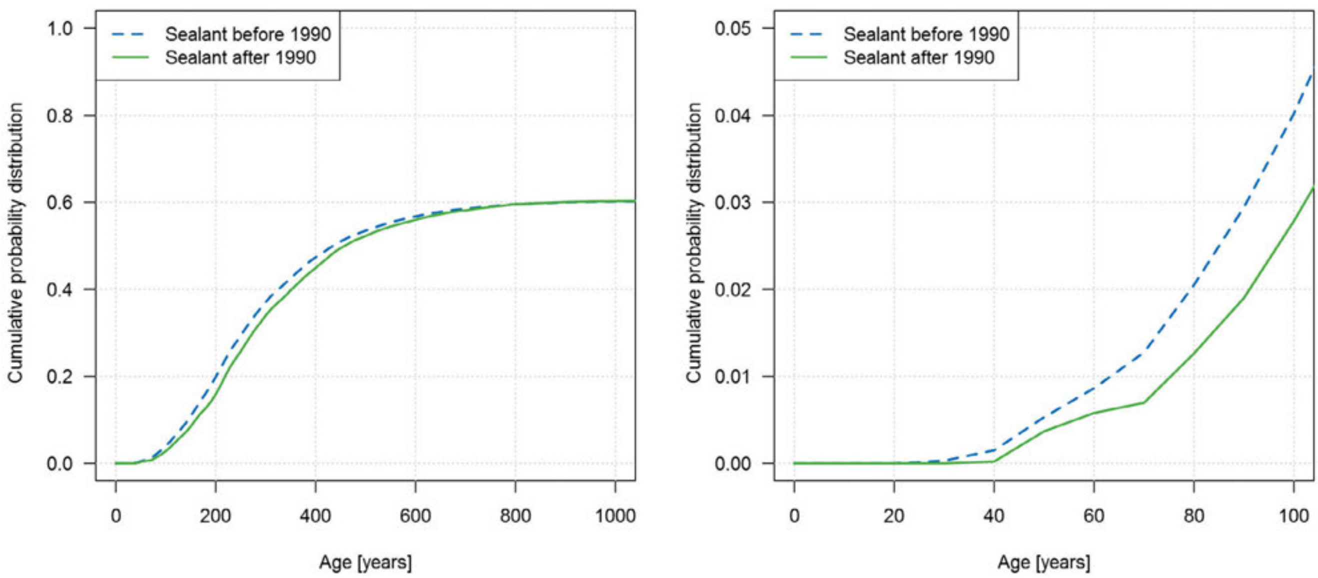

Figure 5: Probability of failure of sealant piping as function of age

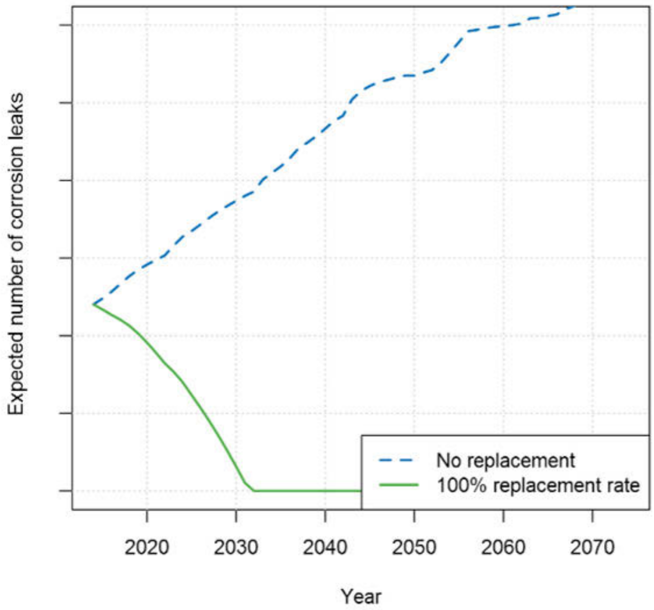

Figure 6: Expected number of corrosion failures in valve stations as function of time for the base-case scenario

The probability distribution of the time to failure of the valve station follows from the probability distribution of the time to failure of each of its D&S pipes. The expected number of failures across the entire Gasunie network in a given year is the sum of the probability of failure of each individual valve station in that year. Calculating this expected number of failures for all future years results in a curve for the future evolution of the expected number of failures.

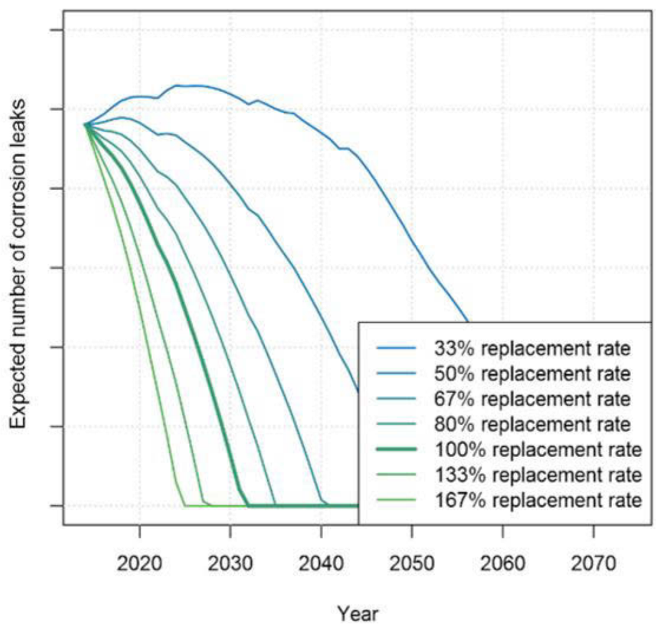

Figure 7: Expected number of corrosion failures in valve stations as function of time for several scenarios

Figure 6 shows the expected number of corrosion failures at valve stations as function of time assuming the current, constant replacement rate or base-case scenario. Also shown is the curve for the scenario if GNIP were not executed ('no replacements'). From this figure, it follows that without GNIP, the expected number of station failures in the network is continuously increasing during the simulated period of fifty years.

This result underpins Gasunie's decision to execute the GNIP program for valve stations. At the current replacement rate, the expected number of station failures in the network is continuously decreasing, reaching zero the moment all stations are replaced.

Similar curves of the number of expected failures over time can be calculated assuming a different number of valve stations replaced each year.

Figure 7 shows the expected number of failures in the entire Gasunie network as function of time assuming several other replacement rates relative to the base-case scenario, namely a replacement rate of 33%, 50%, 67%, 80%, 133% and 167% of the base-case rate.

These curves show that the replacement rate can be lowered to a certain extent.

When the replacement rate is reduced too much (down to 33% and 50%), the expected number of failures will increase and exceed the current, acceptable level in the first years.

A replacement rate of about 67% of the current rate is found to be acceptable while still maintaining the current number of failures per year.

Other simulations were executed, investigating the effect of for example changing the prioritisation order of stations to be replaced.

These simulations show that prioritising on age (older stations first) and configuration (certain types of valves first) results in minimizing the number of failures per year thereby minimizing the risk.

These findings were taken into account in a re-assessment of the required replacement rate within GNIP. As a result, Gasunie decided to lower the rate with 33%. With this decision, significant CAPEX investments are postponed, while at the same time the replacement process becomes better manageable.

CONCLUSIONS

Based on the work performed, the following conclusions can be drawn:

- Results from the GVP confirm the necessity of replacing valve stations in order to reduce the risk of incidents with loss of containment;
- Information generated in the GVP is used as input for decisions to adjust GNIP. In particular, for valve stations the replacement rate could be reduced with 33%, while still maintaining an acceptable risk;
- Information generated in the GVP is used to identify the valve stations that have the highest probability of failure based either on design wall thickness and/or age. By prioritizing valve stations for replacement based on year of installation and age, the risk reduction can be maximized.

RECOMMENDATIONS

Several detailed recommendations were identified, most importantly relating to adjustments of the GNIP program to maximize the risk reduction at the lowest costs. Furthermore, possible improvements of the management and execution of the GVP project, tests and analyses performed were identified in order to improve the quality of data and information generated during the GVP.

Footers

1. Recently GTS has decided to stop complete renovation of gas delivery stations and to focus on maintenance.
2. As figure 5 shows, the cumulative probability reaches 0.6 instead of 1. This is caused by the fact that a significant amount of sealant piping hardly corrodes, according to the corrosion rate probability distribution (see figure 4). The cumulative probability of failure will therefore not reach 1.

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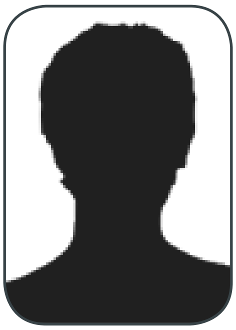

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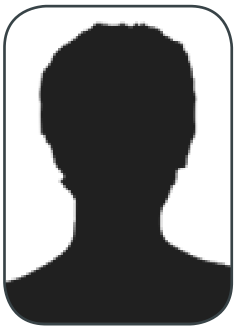
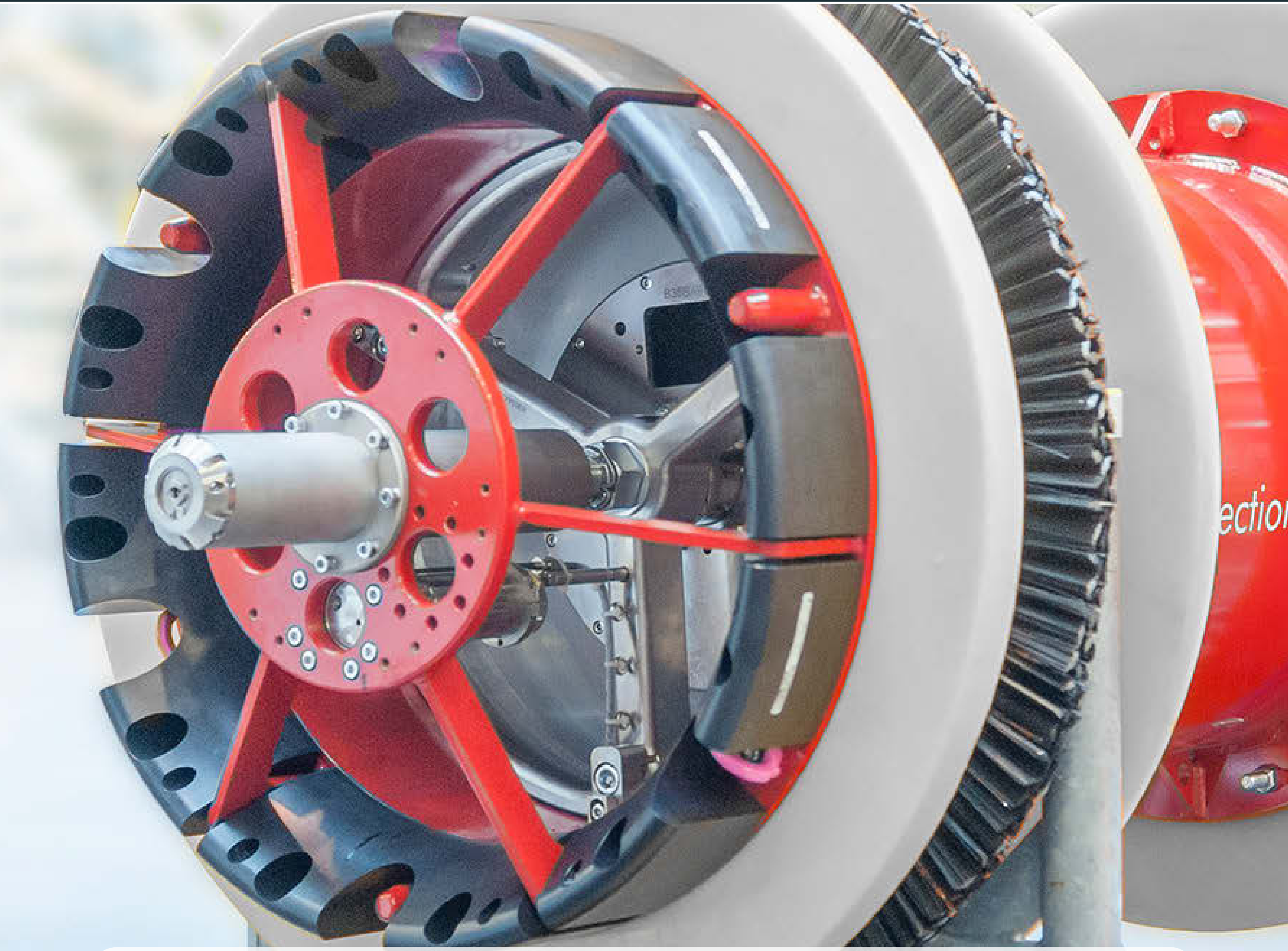


Data-driven Approaches to Pipeline Cleaning

Otto Huisman > ROSEN Group



Abstract

Data-driven approaches are gaining momentum in the pipeline industry. Proactive pipeline maintenance requires the collection and management of data from cleaning programs for future use. This paper illustrates an approach which allows pipeline operators the opportunity to build up a database of information on their assets from standard cleaning runs. Intelligent Gauge Plates and Pipeline Data Loggers (PDLs) can also be integrated in the tool's setup for more comprehensive analysis. A wide range of analytics can be brought to bear upon these databases. The resulting knowledge of the pipeline conditions offers a greater degree of confidence that a line is ready for further in-line inspection, ultimately increasing first-run success rates while reducing risk.

THE NEED FOR PIPELINE CLEANING

The efficient operation of a pipeline is dependent upon maintenance of the internal diameter to ensure optimal flow of the medium. There are a range of significant processes at work inside a pipeline working to decrease flow efficiency. Primarily, ongoing accumulation of deposits which can either cause damage through abrasion or encourage corrosion as a result of the deposits. Compromised pipeline surfaces prohibit corrosion inhibitors from being applied consistently. Product contamination can result, and system contamination can complicate the preparatory work necessary to ensure high quality data from an inline inspection (ILI).

The absence of a cleaning regime can dramatically affect the efficiency, safety, and reliability of the entire network. Foreign matter and buildup can damage the integrity of a pipeline, encourage the formation of corrosion and pipe thinning, and will almost certainly reduce throughput.

As can be seen in Figure 1 below, even smooth deposits can result in a loss of throughput, anywhere between 10-35% in the case of uneven deposits.

Effective cleaning programs are about optimization of the maintenance budget to reduce inefficiencies, maximizing pipeline uptime and product throughput, and extending the lifespan of the asset.

A wide range of cleaning tool technologies exist, including unidirectional and bi-directional tools ranging from light to heavy duty, and equipped with brushes, sealing and scraper discs and magnets to suit.

It is even possible to include speed control options in the newest generation of tools (see Figure 2).

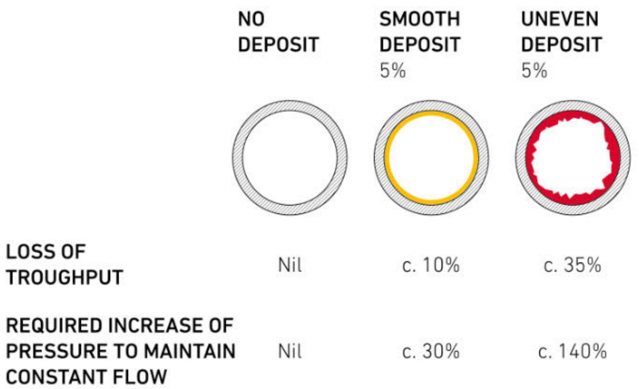


Figure 1: Loss of throughput in the case of pipeline deposits

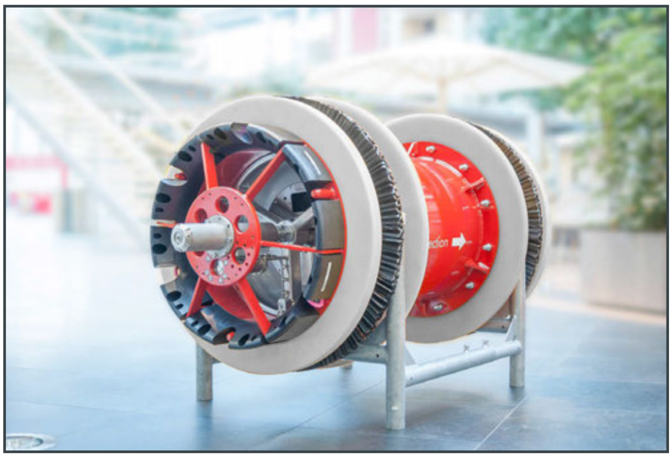


Figure 2: Speed control to optimize cleaning tool operation

THE EMERGENCE OF DATA-DRIVEN APPROACHES

Recent years have seen the emergence of data-driven approaches in a wide range of industries. The pipeline industry is no exception.

This phenomenon can be attributed to the increasing popularity of approaches such as Risk-Based Inspection and Risk-Based Maintenance Management Frameworks. Data-driven approaches are methods originally developed in the computational sciences in which decisions made are based on the collection and analysis of data rather than pre-conceived ideas or existing knowledge about what is happening in the system.

All too often, no data is captured on cleaning run conditions with regards to type, volume, or nature of the debris removed during the process. This means that operators may be missing tangible information regarding pipeline conditions that could provide guidance on whether an in-line inspection can be conducted smoothly, or if the cleaning program is effective.

This may result in uncertainties and increased risks for the efficient transportation of products and operational cleaning or inspection tool runs.

> *"Effective cleaning programs are about optimization of the maintenance budget to reduce inefficiencies, maximizing pipeline uptime and product throughput, and extending the lifespan of the asset.*
> Otto Huisman

Figure 3: Ruggedized field tablet with custom form for data collection

> *The systematic collection, organization and management of cleaning data will facilitate a wide range of analytical approaches.*
>
> Otto Huisman

Pipeline data collection

The concept behind data-driven cleaning is quite simple: collect as much data as possible during launch, cleaning run and receipt of the cleaning pig, and use this information to accurately determine the internal pipeline condition, as well as possible improvements to the tool configuration, tool speed inside the line, inspection interval, etcetera.

Implementing such approaches successfully requires the collection of significant amounts of data to drive a robust set of analytics, which in turn provide inputs into planning and maintenance processes. In the pipeline arena, significant complexity is introduced due to the need to combine various design and operational variables, including pipeline diameter, pressure, etcetera.

ROSEN's new Cleaning Analytic Service was developed specifically to address these issues and provides pipeline operators with the opportunity to build up a database of information on their assets from standard cleaning runs. The service captures information from multiple sources at the beginning and end of each cleaning run.

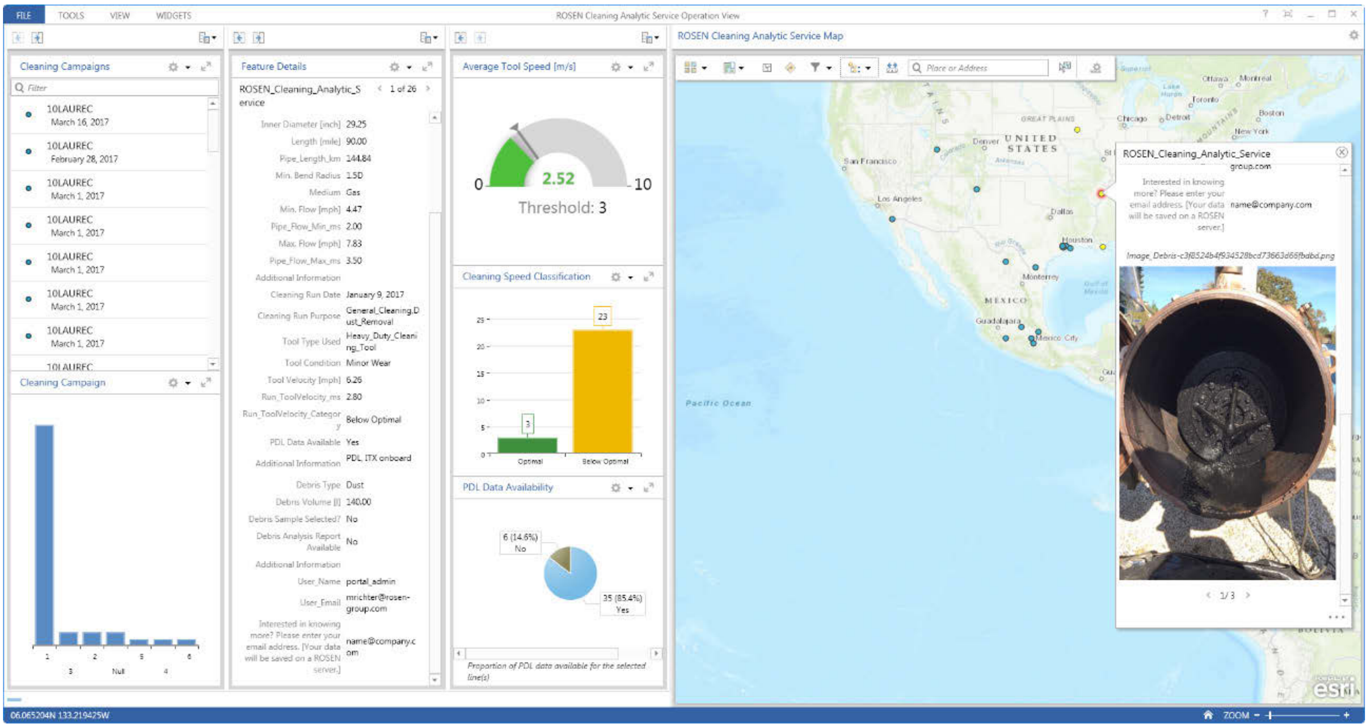


Figure 4: KPI Dashboard presenting summary data and statistics

The Service consists of three main components:

1. Smart Monitoring. Data such as trap conditions, received tool conditions, debris type and volume, and photographic evidence is captured and uploaded in-field using ruggedized (and if necessary, ATEX certified) hardware such as tablets (Figure 3). Operational cleaning data can also be collected by incorporating intelligent units such as ROSEN Pipeline Data Loggers (PDL) and Intelligent Gauge Plates into standard cleaning tools. Pipeline Data Loggers collect and store operational data during a pipeline inspection. They provide operators with detailed time dependent data such as temperature of the medium, pressure conditions in the pipeline, including differential pressure and acceleration, even indication of bends including bend angle. The latest PDLs can be attached to any standard cleaning tool and can record for more than 30 days and up to 500 km (310 miles) of inspection. Intelligent gauge plates are a newer technology, developed to assess the internal geometry of the pipeline, able to detect internal deformations which may restrict flow or prevent the passage of an ILI tool.

2. Data Management refers to the transfer of the captured data to a secure ROSEN cloud. Often, Wi-Fi or cellular data connections are available directly in the field. If these are not available, upload can take place as soon as a data connection can be established. From the in-field device, data captured in the form is transferred to a hosted database for analysis and monitoring of the cleaning program. A web dashboard is a key part of the service. This provides a constantly updated view of cleaning operations data (Figure 4) which has been uploaded. KPIs can be configured in the dashboard to summarize specific data which is collected in the field, providing potentially valuable insights to inform decision making, and if necessary, trigger more detailed investigations into problematic pipeline locations. Once the data is uploaded It is also possible to draw upon the wealth of other internal databases to better inform the analyses and potential recommendations using a range of data mining and machine learning approaches.

3. Assessment includes the analysis of existing data and detailed reporting. The collective assessment of Operational parameters and monitoring of tool behavior during the run can be utilized to detect and locate restrictions or deposits in the line and provide information on cleaning progress and effectiveness, while verifying operational pipeline conditions. When applied to consecutive runs, such an approach enables the systematic build-up of knowledge about a pipeline's development over time. A wide range of analytics can be brought to bear upon these databases, including trending of tool disc wear over time, analyses of differential pressure patterns, and ultimately, determination of the optimal way forward with regard to cleaning tool configuration, cleaning interval, and optionally, flow-assurance modelling. It is important to note here that expert knowledge still remains a critical component in the equation, specifically in the area of interpretation of results.

> *"The resulting knowledge of the pipeline conditions offers a greater degree of confidence that a line is ready for further in-line inspection, ultimately increasing first-run success rates while reducing risk*
>
> Otto Huisman

Figure 5:
Cleaning tool PDL data analysis showing significant pipeline deformation led to a stuck tool. Buildup of pressure eventually dislodged the tool enabling run completion

OUTCOMES

The systematic collection, organization and management of cleaning data will facilitate a wide range of analytical approaches. Photographic evidence, while difficult to employ within an automatic processing chain, can be extremely useful as reference material. The condition of the cups and the disks on the tool and the amount and type of debris that is received can tell much about a pipeline's current operational status.

By analyzing the data from these units, it is possible to verify general pipeline conditions. Specifically, detection and location of restrictions and deposits in the line can be detected by monitoring tool behavior and differential pressure through various data integration and analytical steps (Figure 5).

Outcomes of analyses might range from recommendations for improving cleaning tool configuration to the identification and assessment of specific problem areas inside the pipeline from detailed PDL analysis. Proactive flow-assurance modelling could be employed for specific cases.

Data-driven approaches to pipeline cleaning are a quantitative approach to pipeline maintenance. The implementation of such approaches requires collection and management of data from cleaning programs for future use. We are currently witnessing a significant move towards automated evaluation of pipeline related data.

Analysis and expert interpretation of this data will ultimately benefit any additional process by offering more information from the beginning, and potentially decreasing the workload of in-line inspections.

In a system that can operate in near real-time, status alerts can be provided to give operators critical feedback such as when there is a tool in the line, when a cleaning run was successfully completed, or when a specific problem has occurred. The on-device forms can be configured to collect the required information for such notifications. The resulting knowledge of the pipeline conditions offers a greater degree of confidence that a line is ready for further in-line inspection, ultimately increasing first-run success rates while reducing risk.

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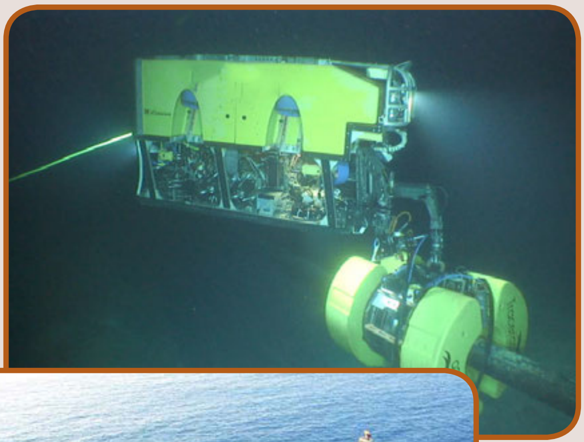
Offshore Technologies



The next issue of Pipeline Technology Journal (ptj) will address challenging pipelines.

This is a great opportunity for skilled authors to submit insightful papers and to contribute to the global pipeline industry's constant professional exchange.

Trial of a Process for the Identification of Reduced Depth of Cover on Buried Pipelines

Daniel Finley; Simon Daniels; Klaas Kole; Michiel Roeleveld > ROSEN Group
Paul Ogden > National Grid

Abstract

Third-party interference is widely documented as being a major cause of damage to buried pipelines. In addition to routine surveillance, maintaining a minimum depth of cover is recognized as a key means of mitigation against third-party interference. We know that the depth of cover over pipelines can change with time. Current techniques available for measuring depth of cover on buried pipes require significant effort to produce a high-resolution survey for an entire pipeline.

A UK Innovation project completed for National Grid Gas Transmission has successfully demonstrated a methodology to identify reduced depth of cover over an entire pipeline. This methodology combines ground elevation data with high-resolution inertial measurement unit (IMU) data collected during inline inspection to calculate the pipeline depth of cover.

GPS and pipe depth measurements have been used to verify the accuracy of this method. Using the pipe centerline derived from the IMU data, and ground elevation data collected using light detection and ranging (LiDAR) techniques, depth of cover has been calculated to an accuracy of ±0.149 m root mean square error.

This paper describes the key project steps associated with planning, data collection, data processing, and the validation of results to demonstrate that pipeline depth of cover over an entire pipeline can be accurately determined.

INTRODUCTION

Maintaining a minimum depth of cover is recognized as a key means of mitigation against third-party interference. The United Kingdom Onshore Pipeline Operators' Association (UKOPA) good practice guide for managing pipelines with reduced depth of cover [1] states that the best way of determining pipeline depth of cover is to take measurements as part of an over-line survey. The guide recommends measurements should be taken at 50 m intervals but this should be modified depending on topography of the land and any known local issues such as ground erosion.

ROSEN Group (ROSEN) and National Grid Gas Transmission (NGGT) have trialed a new methodology to identify reduced depth of cover over an entire pipeline. Knowledge of the locations of reduced depth of cover can help NGGT reduce the likelihood of third party interference events occurring.

METHODOLOGY

Ground Elevation Data

Ground elevation data can be collected using several methods. Accurate data for small areas can be collected using differential global positioning system (DGPS) survey equipment. To capture ground elevation data on a larger scale, a LiDAR sensor can be attached to aircraft. LiDAR is a remote sensing method which uses laser light to measure distance to a target and is commonly used to map terrain and surface objects. The advantage of this method is that a large amount of highly accurate data can be collected allowing large areas to be surveyed efficiently.

Internal Inspection

Standards for operating high pressure pipelines require that the condition of a pipeline is established periodically. The condition is established by the use of internal inspection tool on those pipelines which can be monitored using such devices. The inspection device typically includes systems to detect corrosion and geometric anomalies such as dents. In addition, inspection devices often include an inertial measurement unit (IMU), these units contain gyroscopes and accelerometers and are used to calculate position of the inspection device. The IMU data can be linked to known reference locations along a pipeline route to provide an accurate pipe centerline as a series of X, Y, and Z coordinates.

Depth of Cover Estimation

The methodology trialed to estimate depth of cover combines ground elevation data with an accurate pipe centerline derived from internal inspection.

DEPTH OF COVER REQUIREMENTS

In the United Kingdom (UK) guidance on minimum depth of cover for onshore high pressure pipelines is provided in IGEM/TD/1 [2] and PD 8010 [3]. NGGT operate their high pressure pipelines in accordance with IGEM/TD/1 Edition 5.

Table 1 provides a summary of the minimum depth of cover requirements of IGEM/TD/1 (all editions), PD 8010 and other relevant international standards.

Location / Spec.	IGE/TD/1 Edition 1	IGE/TD/1 (Ed. 2, 3 & 4)	IGEM/TD/1 Edition 5	PD 8010-1:2015	ASME B31.8 [4]	AS 2885.1[5]
All (m)	0.91 (3 ft)	1.1				
Rural (m)			1.1	0.9	0.61 (Class 1) 0.76 (Class 2)	0.75
Suburban (m)			1.1	1.2	0.76 (Class 3 & 4)	0.9
Roads (m)			1.2	1.2	0.91	-
Watercourses, canals, rivers (m)			1.2	1.2		1.2
Railways (m)			1.4	1.4 - 1.8	0.91	-
Rocky Ground (m)				0.5		0.9 (W) 0.6 (T1, T2) 0.45 (R1, R2)

Table 1: Standards Requirements for Minimum Depth of Cover

Key:

R1 – Rural	W - Submerged
R2 – Rural Residential	Class 1 – Rural
T1 – Residential	Class 2 – Rural residential
T2 – High Density	Classes 3 & 4 - High density

DEPTH OF COVER ASSESSMENT

The methodology was trialed on a 36" diameter, 45 km pipeline in the UK.

Pipe Centerline

Following completion of the internal inspection the IMU data was processed to produce an accurate pipe centerline. The output from the processing is a spreadsheet containing a series of X, Y and Z coordinates, Figure 1. Points can subsequently be imported into a geographic information system (GIS) and used to create a pipe centerline polyline feature.

Ground Elevation Data

There were two sources of ground elevation data used within this trial, the Environment Agency (EA) LiDAR and Ordnance Survey Terrain 5 data.

The EA [6] offer LiDAR data with a spatial resolution of between 25 cm and 2 m. It is currently stated by the EA that accurate elevation data is available for over 75% of England. The absolute height error is quoted to be less than ±15 cm. This is the root mean square (RMS) error.

The Ordnance Survey (OS) Terrain 5 data [7] has a quoted height error of ±1.5 m. This is the RMS error for urban and major communication routes. For rural and mountain and moorland areas the error is higher at ±2.5 m. The spatial resolution for all OS Terrain 5 data is 5 m.

log dist. [m]	latitude [deg]	longitude [deg]	height Z [m]	MARK_PNT
0.002	52.54601140	-1.17715253	85.938	T
2.646	52.54600745	-1.17711417	85.934	F
3.443	52.54600619	-1.17710264	85.93	F
6.419	52.54600176	-1.17705946	85.92	F
7.551	52.54600011	-1.17704303	85.911	F
7.875	52.54599963	-1.17703834	85.896	F
8.14	52.54599924	-1.17703451	85.868	F
8.386	52.54599887	-1.17703100	85.826	F
8.632	52.54599851	-1.17702753	85.766	F
8.919	52.54599809	-1.17702358	85.678	F
9.304	52.54599754	-1.17701838	85.541	F
16.037	52.54598812	-1.17692823	82.959	F
17.946	52.54598541	-1.17690261	82.237	F
18.277	52.54598493	-1.17689809	82.125	F
18.546	52.54598453	-1.17689436	82.049	F
18.795	52.54598417	-1.17689083	81.996	F
19.038	52.54598382	-1.17688734	81.96	F
19.3[illegible]	[illegible]8344	[illegible]	81.938	F

Figure 1: Example of points provided from post inspection data processing

Figure 2: Example Depth of Cover Report
(Aerial imagery source: Esri, DigitalGlobe, GeoEye, Earthstar Geographisc, CNES/Airbus DS, USDA, USGS, AeroGRID, IGN and the GIS User Community)

Given the better spatial resolution and greater accuracy of the EA LiDAR data, this was the preferred dataset for use in this trial. However, examination of the available EA LiDAR data identified that there was not full data coverage of the trial pipeline. A 6 km missing section of EA LiDAR data was supplemented with OS Terrain 5 data for the trial.

Reporting

A key requirement is providing a depth of cover report for the pipeline. Figure 2, shows an example report using color bands to represent the estimated depth of cover along the pipeline. Table 2 shows the classification that has been used for the field trial.

Classification	Depth of Cover Range (m)	Colour
1	Depth < 0.6	Red
2	0.6 m ≥ Depth < 1.1 m	Orange
3	1.1 m ≥ Depth ≤ 2.5 m	Green
4	Depth > 2.5 m	Blue

Table 2: Classification for reporting depth of cover

Figure 3 shows an example of ground and pipe elevation plotted according to distance along the pipeline. At this location the pipeline crosses a series of embankments and ditches. The bottom image is a hillshade rendering of ground elevation data to aid visualization. The example demonstrates how the inspection tool has measured the change in pipe elevation as the pipe passes beneath the ditch crossing. The increase in depth of cover associated with the two embankments is also evident.

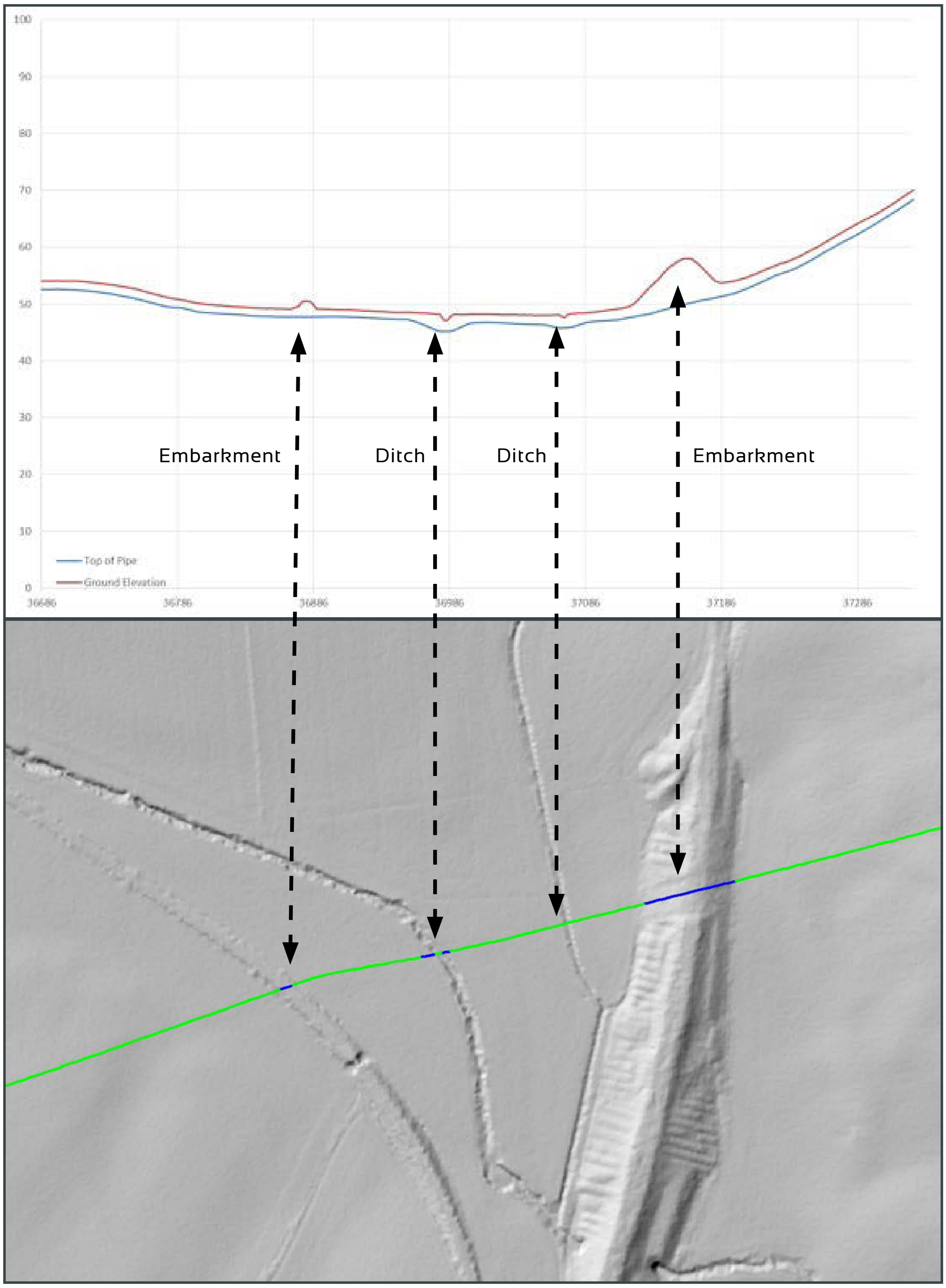


Figure 3: Example of ground and pipe elevation combined where an embankment and ditch (© Environment Agency copyright and/or database right 2015. All rights reserved)

INFIELD VERIFICATION

To assess the accuracy of the results obtained from the depth of cover assessment, infield verification was performed along 10 sections of the pipeline route. The depth of cover and pipeline position were measured at regular intervals (approximately 2 – 3 m) using a Vivax Metrotech vLoc-5000 pipe and cable locator, the position was recorded using a Topcon Hiper SR GNSS unit and Topcon FC – 500 GPS unit.

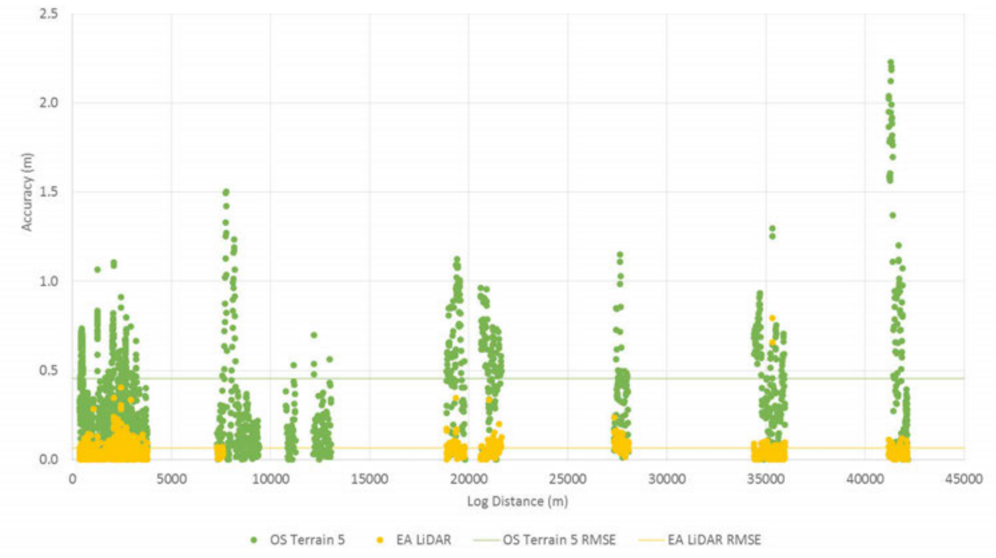


Figure 4: Accuracy Assessment of Ground Elevation Data

It can be seen that the OS Terrain data has a lower accuracy than the EA LiDAR data.

The OS Terrain data has a lower stated accuracy for the product and also has a lower resolution.

The consequence of lower resolution is that the detail of ground features is missing from the data, see Figure 5.

This can be seen at distances 2120 m and 2320 m.

Ground Elevation Data

To assess the accuracy of ground elevation data a comparison between infield measurements, EA LiDAR and OS Terrain 5 data was made. Figure 4 shows an accuracy assessment of the EA LiDAR and OS Terrain data against in field measurements. A ±0.07 m RMS error was calculated for the LiDAR data and ±0.46 m for the OS Terrain data. This is within the stated accuracy for each product.

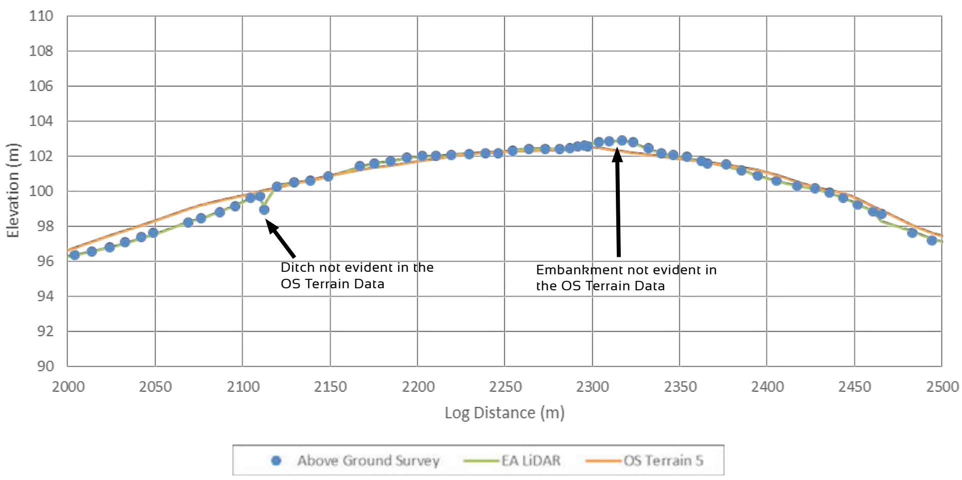


Figure 5: Comparison of Ground Elevation Data sets

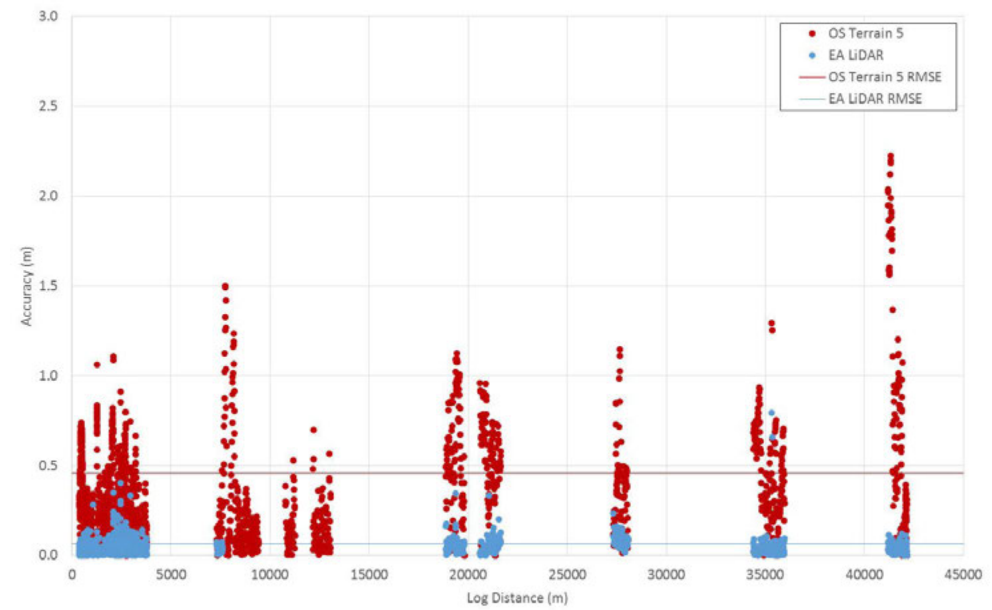


Figure 6: Accuracy Assessment at all 10 Pipe Sections

Depth of Cover

To assess the accuracy of depth of cover results, a comparison between the estimated depth of cover and infield measurements was performed.

Figure 6 shows the accuracy assessment using the pipe centerline data for all 10 pipe sections. This includes depth of cover calculated using EA LiDAR data and OS Terrain 5 data.

The RMS error for depth of cover based on EA LiDAR data is ±0.15 m and for the OS Terrain data is ±0.46 m.

CONCLUSIONS

- The trial has successfully demonstrated ROSEN's methodology to estimate the depth of cover over pipelines. This includes producing an accurate pipeline centreline from data obtained during a routine internal inspection, combined with ground elevation data available from the Environment Agency (EA) to calculate depth of cover.
- The results of the calculation have been validated against infield depth of cover measurements obtained using a pipe and cable locator. The accuracy of the depth of cover results has been calculated using a root mean square (RMS) error method. This has determined an overall accuracy of ±0.15 m using EA LiDAR data.
- Infield ground surface measurements were compared with the EA LiDAR and OS Terrain data. A RMS error of ±0.07 m was calculated for the EA LiDAR data and ±0.46 m for the OS Terrain data. These show that the accuracy of the data is within the stated product specifications.

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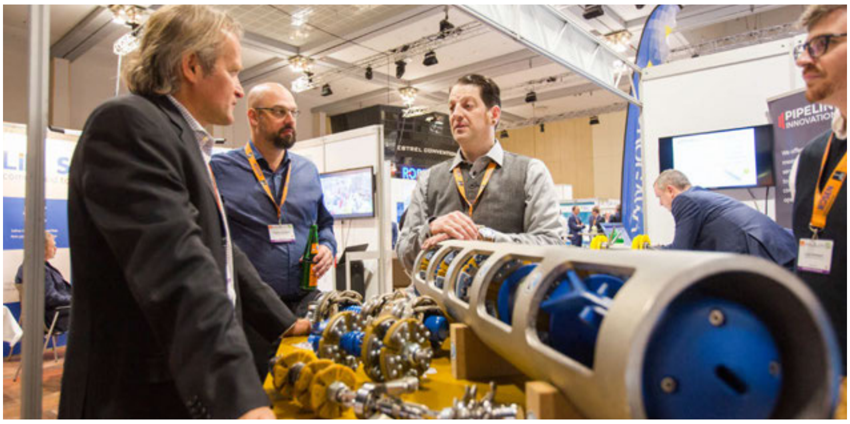

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www.optasense.com

Pergam Suisse
Switzerland
www.pergam-suisse.ch

PSI Software
Germany
www.psioilandgas.com

sebaKMT
Germany
www.sebakmt.com

SolAres (Solgeo / Aresys)
Italy
www.solaresweb.com

Materials

egeplast international
Germany
www.egeplast.de

Monitoring

Krohne Messtechnik
Germany
www.krohne.com

Pump and Compressor Stations

TNO
The Netherlands
www.pulsim.tno.nl

Repair

CITADEL TECHNOLOGIES
United States
www.cittech.com

Clock Spring
United States
www.clockspring.com

RAM-100
United States
www.ram100intl.com

T.D. Williamson
United States
www.tdwilliamson.com

Research & Development

Pipeline Transport Institute (PTI LLC)
Russia
www.en.niitn.transneft.ru

Safety

DEHN & SÖHNE
Germany
www.dehn-international.com/en

HIMA
Germany
www.hima.de

TÜV SÜD Indutrie Service
Germany
www.tuev-sued.de/is

Standards & Regulations

DNV GL
Norway
www.dnvgl.com

DVGW - German Technical and Scientific Association for Gas and Water
Germany
www.dvgw.de

Surface Preparation

MONTI - Werkzeuge GmbH
Germany
www.monti.de

Trenchless Technologies

GSTT - German Society for Trenchless Technology
Germany
www.gstt.de

Rädlinger Primus Line
Germany
www.primusline.com

Valves & Fittings

AUMA
Germany
www.auma.com

IMI Precision Engineering
Germany
www.imi-precision.com

Zwick Armaturen
Germany
www.zwick-armaturen.de

Event Calendar

International Pipeline Conference 2018	24 - 28 September 2018	Calgary, Canada
International Pipeline Expo 2018	25 - 27 September 2018	Calgary, Canada
gat | wat 2018	23 - 25 October 2018	Berlin, Germany
ptc Side Conference on Qualification & Recruitment	**18 March 2019**	**Berlin, Germany**
ptc Side Conference on Public Perception	**18 March 2019**	**Berlin, Germany**
14th Pipeline Technology Conference (ptc)	**19 - 21 March 2019**	**Berlin, Germany**

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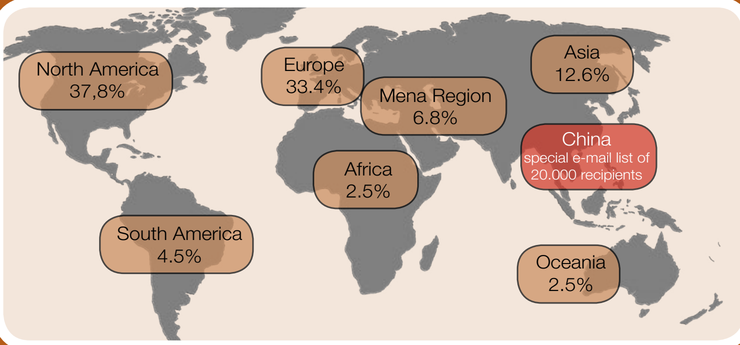

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